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SCALED MODEL STUDIES OF HEAVY OIL RECOVERY USING HORIZONTAL WELLS IN HEAVY OIL RESERVOIRS

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EXECUTIVE SUMMARY

Heavy oil reservoirs account for approximately 2.1 trillion barrels of world's proven oil reserves. A large fraction of these heavy oil deposits are found in Canada. Most of these reservoirs produce only 2-10 percent of the oil in place (IOIP) by primary depletion. The challenge in producing heavy oil is finding solutions to overcome problems related to high oil viscosities and resultant low oil mobilities. Even though the industry standard for producing heavy oil is the use of thermal methods, thermal methods appear to be economically marginal for reservoirs thinner than 10 m. In this regard, the possibility of waterflooding heavy oil reservoirs is investigated in this research.

Waterflooding of heavy oil reservoirs has never been a viable technique due to high mobility contrast between water and oil. High mobility of the displacing phase leads to premature water breakthrough and poor oil recovery due to profuse viscous fingering. However, the recent advancement in horizontal well technology has opened up the possibility of using waterflood as an attractive alternative to other enhanced oil recovery techniques for heavy reservoirs with moderate oil viscosities. Horizontal wells contact the reservoir over a large surface area and allow quick depletion of the reservoir. A series of experiments was conducted to study the feasibility of horizontal well implementation in Aberfeldy heavy oil reservoir. The oil viscosity of this reservoir is in the range of 700-4000 mPas. Experiments in scaled model were conducted to study the effect of various parameters, such as, oil viscosity, reservoir thickness, wellbore diameter, reservoir heterogeneity (shale breaks and natural vertical fractures), etc. Ultimate oil recoveries of up to 50 percent IOIP were observed. The presence of horizontal shale breaks did not alter the recovery performance of the waterflood; however, the presence of vertical fractures decreased oil recovery drastically. Such natural fractures are considered to be beneficial in primary depletion with horizontal wells. The effects of bottom water zone thickness and permeability as well as injection/production well location were also investigated. Oil recovery in the presence of bottom water varied from 6 to 25 percent IOIP depending on the thickness of the bottom water zone. Primary depletion in these reservoirs gives less than 1% IOIP recovery.

A detailed summary follows:

Initial runs showed the effectiveness of a small well diameter (0.17cm) for proper modelling. A realistic diameter of the production well indicated the relative importance of pressure drop effects within the production well to modelling results. The diameter of the injection well had a more pronounced effect on oil recovery performance with a waterflood, but may have been due to transient plugging in the injector.

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Oil viscosity had little effect on oil recovery. Even though water breakthrough was delayed for the lower oil viscosity case, final recovery for 770mPa.s and 6040mPa.s were almost the same. However, recovery during the early stages was higher for the lower viscosity case.

Reservoir thickness had little effect on injection pressure. The injection pressure of the thicker reservoir was approximately 10% greater than that of the thinner reservoir. Oil recovery for the thicker reservoir was more rapid; however, the thin reservoir yielded 15% more of its IOIP displaying a better recovery factor.

Horizontal shale breaks had only minimal effect on oil recovery or injection pressure but did delay water breakthrough.

An oil-to-water zone thickness ratio of 5:1 was found to be the optimum for waterflooding thin reservoirs with bottom water layers.

Horizontal shale breaks in bottom water situations resulted in a 7% reduction in production.

Vertical barriers/fractures led to drastic reduction in oil recovery for reservoirs with or without a bottom-water zone.

The combination of vertical injector with horizontal producer gives the most efficient oil recovery. Vertical injectors with vertical producers give distinctly lower recovery than the horizontal/horizontal or vertical/horizontal schemes.

Limited numerical simulation results show surprisingly good agreement with experimental results.

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Dans le monde entier, il y a actuellement une réserve de 2100 milliards de barils de pétrole lourd. Une bonne partie de ces réserves se trouvent au Canada. Pour la plupart de ces réservoirs, on ne peut extraire que de 2 à 10 % de pétrole lourd par les méthodes de pompage ordinaires. La trop grande viscosité du pétrole lourd est le coeur du problème: elle empêche sa fluidité et son écoulement. Il s'agit donc de trouver de nouvelles méthodes d'extraction. A l'heure actuelle, les méthodes thermiques mises au point par l'industrie ont peu de viabilité économique lorsque la couche d'un réservoir a moins de 10 mètres. La méthode alternative faisant l'objet de cette recherche est le déplacement horizontal d'une nappe de pétrole lourd dans son réservoir par une marée aqueuse.

Les techniques d'injection d'eau ou de vapeur dans un puits vertical pour stimuler une nappe de pétrole lourd se sont avéré peu efficaces à cause de la trop grande différence de fluidité et de mobilité entre la phase aqueuse et la phase d'huile visqueuse. L'eau sous pression, plus mobile, forme des canaux d'infiltration et s'y écoule sans entraîner de pétrole. Par contre, grâce à la nouvelle technologie du puits horizontal, la marée aqueuse est capable de déplacer des nappes de viscosités moyennes. Le puits horizontal permet une plus grande surface de poussée et déplace uniformément la nappe entière du réservoir vers le puits de production. On a fait des essais à Aberfeldy pour étudier l'efficacité d'extraction de pétrole lourd par puits horizontal. Le pétrole de ce réservoir a une viscosité variant de 7 à 40 poises. Les essais ont été conçus en contrôlant différents paramètres tels que la viscosité du pétrole, l'épaisseur du réservoir, le diamètre du puits de forage, l'hétérogénéité du réservoir (présence de schistes ou de faille verticale). On a observé un potentiel d'extraction pouvant aller jusqu'à 50 % dans les meilleures conditions. La présence d'un bouchon de schistes horizontaux dans le réservoir ne ralentit pas la poussée aqueuse. Par contre la présence d'une faille verticale perturbe considérablement l'efficacité du processus d'extraction. On a aussi étudié les effets de la formation d'un lit aqueux et la perméabilité au fond du réservoir, ainsi que l'importance du positionnement des puits d'injection et de production. L'extraction peut diminuer de 25 à 6 % suivant l'importance d'un lit aqueux au fond du réservoir. Par méthode de pompage ordinaire en puits vertical, l'extraction ne produit que 1 % du pétrole lourd contenu dans ce réservoir.

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Un sommaire détaillé suit:

Les premiers résultats démontrent l'éfficacité d'un puits a petit diamètre (0.17cm) comme étant un bon modèle. Le diamètre réaliste du puits producteur indique l'importance relative des effets de chutes de pressions dans le puits producteur comparé au puits modèle.L'effet du diamètre du puits d'injection est plus prononcé en ce qui est de la recouverte de pétrole par "waterflood", (production secondaire par injection d'eau). Ceci pourait être du a un phénomène de blocage de l'injecteur.

La recouverte est peu affectée par la viscosité de l'huile, bien que la production d'eau soit retardée lorsque la viscosité est basse.Les recouvertes finales de 770mPa.s et de 6040mPa.s sont presque les mêmes,bien que la recouverte initiale soit plus haute lorsque la viscosité est basse.

Les pressions d'injections sont peu affectées par l'épaisseur du réservoir. La pression d'injection d'un réservoir plus épais étant 10% plus élevée que celle d'un réservoir plus mince.La recouverte d'huile dans un réservoir plus épais est plus rapide, bien que le réservoir plus mince produit 15% de plus de son "IOIP" (huile en place initiale), et donne donc un meilleur facteur de recouverte.

Les couches d'argiles horizontales affectent peu la recouverte d'huile ou la pression d'injection, par contre ils retardent la production d'eau.

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L'optimum pour un "waterflood" de réservoir mince ayant des couches aqueuses au fond, serait un rapport d'épaisseur huile/eau de 5:1.
Les couches d'argiles horizontales dans les réservoirs a fonds aqueux donnent une réduction de productivité de 7%.

Des barrières verticales ou des fractures réduissent dramatiquement les recouvertes,que ce soit dans des réservoirs a fonds aqueux ou non.

Les meilleurs recouvertes se réalisent avec des puits d'injection verticaux et des puits producteurs horizontaux.Des puits d'injection verticaux avec des puits producteurs verticaux donnent de plus basses recouvertes qu'un système horizontale/horizontale ou verticale/horizontale.

Le résultat des quelques simulations numériques sont en tres bon accord avec les résultats expérimentaux.

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1.0 INTRODUCTION

Decreasing conventional oil reserves will lead to increasing importance for heavy oils in Western Canada. Steam injection is known to be an effective method of recovering a larger amount of oil from heavy oil reservoirs with very little primary production; however, the effectiveness of steam injection depends on how favorable the reservoir conditions are. Over half of the heavy oil occurs in reservoirs that are not suitable for steam injection. This is the case when the formations are too thin (<10 m), depths are too large (>1000 m), injectivity (permeability) is too low or oil saturation is insufficient. Currently, recovery from thin reservoirs on primary production in the Lloydminster region is limited to 4 to 8% of the oil in place. Recovery performance for such reservoirs may be improved greatly if horizontal wells are used along with suitable non-thermal recovery techniques.

Horizontal wells are being recognized as one of the most promising techniques in recovering oil from marginal oil reservoirs (Joshi, 1988). The increasing interest for using horizontal wells is evident from recent studies reported. (Combe et al., 1988; Butler, 1988; Garden and Grace, 1988; Bosio, 1988; Joshi, S.D., 1986,1987, 1988; Proctor et al., 1987; Kossack and Kleppe, 1987). Due to more extensive contact with the reservoir, horizontal wells allow fluid flow at lower fluid velocities still providing total flows which are economic. The applicability of horizontal wells has been tested in the realm of thermal applications, such as steam flooding (Proctor et al., 1987) and steam-assisted gravity drainage (Joshi, 1986). Proctor et al. studied the effect of horizontal wells in a scaled steam flood model using a thin heavy oil prototype. They concluded that the added expense of placing a horizontal well may severely limit its applicability since the recovery was marginally higher than that obtained by vertical wells. Joshi (1986) showed the effectiveness of steam assisted gravity drainage with the aid of horizontal wells. He found that steam assisted gravity drainage produced heavy oil at a rate approximately three times faster than that obtained with cold oil gravity drainage. He also studied the production/injection strategies and concluded that a horizontal injector and producer scheme is better than vertical injector and horizontal producer only for homogeneous reservoir. For cases with shale barriers, a vertical injector with horizontal producer gave better result than horizontal producer and injectors. Also, for homogeneous case, steam injection near the pack top gave higher and faster oil recovery than steam injection near the sand pack bottom. A comparison of his results with theoretical predictions (Butler, 1985) indicated higher oil recovery in experimental results. Note that Joshi used an unscaled physical model. Consequently, results obtained in his study are not correlative to the field performance.

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Several authors have reported numerical simulation studies of steam injection using horizontal wells (Rial, 1984; Gussis, 1985; Combe et al., 1988). Rial (1984) used a horizontal injector and vertical producer configuration and showed that steam injection with such a scheme would lead to 13% increase in ultimate oil recovery by using horizontal injector. This improvement was attributed to better heat sweep and energy control. Combe et al. (1988) studied various injection production strategies with horizontal wells. They observed that the vertical injector and horizontal producer scheme was the most advantageous one. This scheme improved recovery performance considerably in thin reservoirs for which conventional steam flood with vertical wells are not very productive. One of their interesting observations was related to superimposed reservoirs. Improved performance was observed when applying steam drive between two superimposed reservoirs, with the injector in one layer being in the same vertical plane as the producer in the other layer. This was thought to be due to particular nature of heat transfer through the interbedded impervious layer.

This study is aimed at designing a scaled physical model for a prototype using horizontal wells under non-thermal recovery conditions, such as primary depletion, water injection, immiscible gas injection with or without the presence of a bottom-water zone. Conventional recovery techniques for these processes fail to produce any substantial amount of oil. Laboratory studies for this process performed to-date have used unscaled models. Therefore, the quantitative results obtained from these experiments are not applicable in the field. Unscaled models are chosen such that they represent the conditions at some point in the field. However, their dimensions are selected on the basis of the aspect of recovery being studied and/or the physical constraints of the test equipment (Farouq Ali and Redford, 1977; Farouq Ali, Redford and Islam, 1987). Consequently, while unscaled models elucidate some of the mechanisms in the process, they could not be applied to predict field performance. In this regard, scaled models are highly desirable. A scaled model is designed on the basis of the principle of similarity, first enunciated by Newton for systems of solid particles in motion. Such a model is characterized by the ratios of dimensions, forces, velocities, temperature, concentration differences, etc. as those occurring in the field. However, in the view of the scaling problems involved, fully scaled models are seldom attainable. In such cases, a partially scaled model in which some of the scaling criteria are relaxed may be adequate. The question of whether relaxed scaling criteria introduce appreciable errors in the results may be addressed by conducting experiments in different physical models which satisfy different scaling groups. Such a study has recently been performed by Kimber and Farouq Ali (1988a, 1988b) for steam injection problems. This investigation gave valuable insight into the mechanisms involved in the process, and in turn, into the formulation of the mathematical model.

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This information could not be obtained by a mathematical model alone as it is capable of simulating no more than the physical process built into it.

A complete set of dimensionless groups for recovery processes, such as primary depletion, waterflooding, surfactant-assisted water/gas injection, solvent-assisted waterflooding, and immiscible gas flooding, all using horizontal wells has been derived by Islam (1988). The mechanisms involved in these processes has been detailed in recent studies (Islam and Farouq Ali, 1989, 1990).

This study is aimed at scaled model investigation of waterflooding heavy oil reservoirs using horizontal wells with or without a bottom-water zone and theoretical investigation of the same in order to identify different production mechanisms, set screening criteria for target reservoir selection and develop production strategies.

2.0 EXPERIMENTAL APPARATUS AND PROCEDURE

A series of waterflooding experiments was carried out in a scaled physical model. A schematic diagram of the experimental setup is shown in Figure 1. A Beckman 100A Solvent Metering System was used to pump oil or water in the model during the course of the experiment. This pump is capable of delivering fluid from a range of 0.01ml/min. up to 9.99 ml/min. against a maximum pressure of 68,950 kPa with an accuracy of +/- 0.005 ml/min. Throughout the experimental runs, a brine of 2% salt concentration was used. The brine displacement unit consisted of four 3.785 litre Whitey sample cylinders each with a pressure rating of 12,400 kPa. The oil injection unit was a floating piston cylinder with a maximum capacity of 2.546 litres and maximum operating pressure of 20,685 kPa. The aluminum reservoir was designed in house by NOVA HUSKY RESEARCH CORPORATION (NHRC) and manufactured in a local specialty machine shop. The bulk volume of the model was 9 litres and the maximum design operating pressure was 4,825kPa. Its overall inner dimensions were 30cm x 30cm x 10cm height. Separate aluminum spacer blocks allowed operation of the reservoir at heights of 3.35cm, 6cm, and 10cm. These values corresponded to reservoir thicknesses of 3.35m, 6 m, and 10m, respectively. The reservoir model was also equipped with the provision of a vertical injection well. The injection and production wells were made of stainless steel tubing. Two different inside diameter wells of 0.170cm and 0.774cm were constructed, corresponding to field diameters of 7" and 30". The larger well was perforated with 0.178cm holes and wrapped with 100 mesh screen. The smaller well was perforated with 0.073cm holes and wrapped with 200 mesh screen. Wellbore production

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pressure in the reservoir was simulated by using a back pressure regulator of maximum operating pressure of 20,685 kPa.

For the case of bottom-water, the reservoir was unpacked after initial oil flood. The bottom water sand was 100% saturated with 2% brine solution. The saturated oil that was obtained during the saturation stage was then manually packed on top of the bottom-water zone. This constituted the oil pay zone. At this time the shale breaks and vertical fissures were placed in the model reservoir for their respective runs.

The produced fluids were collected in 100ml graduated centrifuge tubes. These tubes were subjected to up to 1,400 rpm rotation in a centrifuge in order to enhance separation between water and oil phases. Injection and production pressures were monitored by two model 1151 Rosemount pressure transducers with a pressure range of 0-3,447 kPa. Metler PE24 and Metler PM4600 balances were used to measure the injected and the produced fluids, respectively. Experimental data were monitored by the use of a Compaq Deskpro computer in which Labtech Notebook (data acquisition system) was instalied. The whole experimental apparatus was constructed at NHRC.

2.1 Packing and Preparation

The reservoir model was dry packed with reservoir sand using a particle distributor. This method produced porosities of approximately 39%. An overburden pressure of 2,070kPa was then applied and a vacuum pulled on the reservoir sand pack for 11-12 hours. For the case of horizontal injector and horizontal producer, brine was imbibed through the bottom horizontal well. Then the model was connected to a pump and a 2% brine solution was pumped through. Accurate mass balance of imbibed and brine throughput allowed determination of the pore volume. Oil was then injected through the upper horizontal well at a rate of 125 ml/hr or less to ensure piston like displacement of the water. The oil flood was continued until water cut dropped below 1%. To ensure that an initial reservoir condition of irreducible water saturation existed, a minimum 1.2 PV of oil was injected and was followed by pressurizing the reservoir up to 1,035kPa.

For the case of horizontal producer and vertical injector, water and oil saturations were carried out through the vertical injector while all productions took place through the horizontal producer.

The waterflood in all runs was conducted through the upper horizontal well at a rate of 200 ml/hr. The weight of brine injected, the inlet pressure, the outlet pressure and the weight of produced

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fluids were parameters recorded by Labtech Notebook. The water to oil ratio was the designated criterion to determine the "end of run" although this criterion was relaxed in certain runs. For most runs, large samples were collected by dividing the whole model sands into equal blocks. Core Lab conducted Dean Stark analysis to measure in situ saturations. Conditions for each run are given in Table 1. Figure 1b shows well configurations for various runs.

2.2 Chemicals

The following materials were used for the experiment.

1. Porous Media: Aberfeldy and Pikes Peaks sand were employed in all runs as noted in Table 1.

2. Two different oils were used.
   - A Aberfeldy reservoir oil with a viscosity of 770mPa.s at 25° C and a density of 0.9463 g/cc for Runs 7 to 15, a third batch of A crude blended with hexane to 770mPa.s was used.
   - B Aberfeldy reservoir oil with a viscosity of 6040mPa.s at 25° C and a density of 0.9746 g/cc.

3. Water Phase: A salt water solution of 2% NaCl was used as the displacing fluid in all runs.

3.0 PRESENTATION OF EXPERIMENTAL DATA

Fifteen waterflood runs were carried out in this study. Thirteen of these runs were carried out using a horizontal injector and horizontal producer. One run was carried out using a vertical injector and horizontal producer. One more run was carried out with vertical injection and vertical producer. Initial reservoir conditions and results of these runs are summarized in Table 1.

3.1 Waterflooding Heavy Oil Reservoirs

Run 1: Base Water Flood Case

The first run was carried out for an Aberfeldy prototype of 10m thickness. The reservoir model was packed with Aberfeldy reservoir sand. An oil flood was carried out with 770 mPa.s Aberfeldy

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reservoir oil until an irreducible water saturation, Swi of 12.6% was established. For this run the larger (0.774 cm) of the two well diameters was utilized for both injection and production wells. Figure 2 shows the oil recovery (IOIP), the injection pressure and the water to oil ratio (WOR) vs. pore volume recovered (PV). As can be seen in Figure 2, approximately 14% of the IOIP was recovered before water breakthrough occurred. Considering that the water was injected with very unfavorable mobility ratio (approximately 400), this early water breakthrough is not unexpected. Oil production continued with increasing water-oil ratios after the initial water breakthrough. As the waterflood continued, an ultimate oil recovery of 38.1% of the IOIP took place before WOR became very high. Throughout the displacement test, the injection pressure declined steadily from 410 kPa to approximately 270 kPa. The WOR increased continuously until approximately 0.8 PV of fluid was recovered then began fluctuating to exceed a WOR of 100 in spikes (Figure 2). The run was shut down after 21.5 hours by which time 1.35 PV of fluid had been recovered. Upon completion of the test, the reservoir model sand was retrieved and analyzed for fluid saturations. Figure 3 shows remaining oil saturation versus dimensionless well length at end of the run. The remaining oil saturation was the highest at the point of where the injection well entered the reservoir and decreased with increasing distance from this point. This finding may be explained by considering the fact that the displacement fluid velocity is greatest near the injection well where the differential pressure between the injection well and the reservoir sand is the greatest. As the distance from the injection point increases, differential pressure decreases, the injection fluid velocity decreases and the sweep efficiency increases. The lower remaining oil saturation values along the production well are consistent with oil displacement was carried out by a uniform water front.

Run 2: Effect of Smaller Production Well Size

Run 2 was a repeat of Run 1 except that the production wellbore inside diameter was decreased from 0.774 cm to 0.17 cm. This lower diameter represents proper scaling of the wellbore (scaling factor of 100). The injector remained at the larger diameter. For this run the initial water saturation was 14.2%. Production data for this Run is displayed in Figure 4. Water breakthrough occurred after producing 7.7% of the IOIP. This value was substantially lower than that of Run 1. A smaller diameter of the production well may invoke additional pressure drop within the production well to restrict the waterflood front to a non-uniform tongue-like shape. This may expedite water breakthrough in a reservoir. However, oil production continued considerably long time after water breakthrough and an oil ultimate recovery of 36.6% of the oil in place took place. This value is very close to the one observed in Run 1. The injection pressure decreased steadily from 440 kPa to 360 kPa during the course of the displacement test. The WOR increased from 0

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to approximately 25 over the length of the run, but increased to maximum values of 90 between 0.8 and 1.2 PV recovered. The transient increase in WOR (0.8 to 1.2 P.V. in Figure 4) was believed to be the result of a water channel which consequently lost communication between the two horizontal wells. Water production appeared to take place in burst of water slugs. This phenomenon is not uncommon where the pressure drop along the production wellbore is a dominant factor. The run was stopped after 2.3 pore volumes of water had been injected over a period of 37.6 hours. Although the WOR had not reached 100, the total water injection exceeded 2.4 pore volumes and the run was stopped. The 0.17 cm production well as used in Run 2 produced similar amounts of oil as in Run 1 but the injection pressure was much more stable. Also, this smaller diameter fulfils the scaling requirements much better than the larger diameter. Consequently, it was decided to use this diameter for the production well for subsequent runs. After completion of the run, sand samples were collected from the reservoir model and were analyzed for fluid saturations. Figure 5 shows of remaining oil saturations along the length of the injection and production wells. In both cases the saturations along the wells are similar and relatively constant, indicating that the overall sweep by the waterflood was relatively uniform from injector to producer. Note that the final reservoir saturation values cannot be used to comment on early water breakthrough which may have been due to a tongue-like water front. Similar to Run 1, saturations along the production well showed similar trends whereas the injection well in Run 2 showed no evidence of varying fluid velocity. This is attributed to the reduced production well diameter which restricted the flow as compared to Run-1 and reduced fluid velocities.

Run 3: Effect of Oil Viscosity

In order to study the effects of viscosity, Run 3 was conducted with an Aberfeldy oil with a viscosity of 6040 mPas. As listed in Table 1, all other parameters were held the same as with Run 2. The irreducible water saturation for this run was 8.8%. Figure 6 shows the recovery and injection pressure data for this run. As can be seen from this figure, 6.7% of the IOIP was produced before water breakthrough took place. This value is close to what was observed in Run 2 with lower oil viscosity. Water breakthrough is a strong function of the instability which is, in turn, a function of the mobility ratio. However, this dependence subsides for very high instability numbers (in the range of 400-1000). This regime of high instability number is called the "pseudostable regime' (Islam and Bentsen, 1987). It is commonly believed that most field water displacements fall under this regime and, therefore, experiments should be conducted in such a way that this regime is established in the laboratory. The prediction of instability number in a horizontal well case is not trivial and they were not calculated in this present study. However, from the observation that the water breakthrough remained fairly insensitive to oil-water viscosity

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ratio, it may be fair to assume that 'pseudostable regime has been established in the present experiments. Oil production continued after water breakthrough and a total of 32.4 percent of the oil-in-place was recovered at the end of the displacement test. Viscosity effects were most noticeable by the injection pressure which increased to 3260 kPa in the first 1.5 hours and then dropped down to 80 kPa after water breakthrough. From this 80 kPa the injection pressure then decreased steadily to 40 kPa, indicating more efficient water channelling than observed in previous runs with low viscosity oil. The water-oil ratio, WOR, increased steadily from 0 to approximately 15 which occurred at 1.15 pore volumes recovered. For the duration of the Run the WOR fluctuated with an increasing trend until reaching 100 which marked the end of the Run. The Run lasted 29 hours with a total water injection of 1.76 pore volumes. Upon completion of the test, the sand samples were collected and analyzed for fluid saturations. The saturations along the production and injection wells are plotted in Figure 7. This figure shows the same general trends as were observed previously. The oil saturation close the water injection point is the greatest and decreases towards the production well. Once again, the variation in fluid velocity is noticeable. Oil saturation along the production well was constant indicating a uniform water front similar as observed in Runs 1 and 2.

Run 4: Effect of Reservoir Thickness

Run 4 was conducted in order to investigate the effect of reservoir thickness. A 6.65 cm aluminum spacer was inserted into the reservoir model to reduce its sand pack thickness to 3.35cm. Other parameters were held the same as in Run 2 with the exception of the type of sand used. Due to a lack of Aberfeldy sand, Pikes Peak reservoir sand was used for this run. Aberfeldy sand is from a regional reservoir typically dirtier and of a smaller particle size than Pikes Peak channel sand. For this particular run, the oil flood rate was lowered to 70ml/hr to ensure piston like displacement which yielded an oil saturation of 88.5%. Recovery and pressure data for this run are plotted in Figure 8. As can be seen in this figure, water cut was positive from the beginning of the run. Note that, due too smaller thickness of the reservoir model, the irreducible water saturation was not quite established in 1.2 pore volumes of oil injection. Analysis of the produced water indicated that initial water production was from the reservoir itself. The imperfect initial conditions left mobile water saturation in the reservoir. Injection water breakthrough is believed to have occurred after about 0.35 PV had been injected. This value is higher than that observed in any of the previous runs. It is difficult to confirm if this delayed water breakthrough is a result of experimental artifacts or real and to be expected in the field. However, the distance between injection and production wells was considerably less than that of the previous runs. Since the injector is at the top and the producer at the bottom on opposite sides of a reduced thickness of

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reservoir, this may be considered analogous to close spacing in the field situation. For heavy oil reservoirs, closer spacing has consistently yielded better sweep efficiencies. Soon after initiation of the waterflood, the WOR increased to 5.3, then decreased to approximately 3 and then steadily rose to approximately 10 after 2 PV of fluid had been recovered. Ultimate oil recovery of 51.6% of IOIP occurred after 4.65 PV of water had been injected. Injection pressure averaged 350 kPa at the start of run and steadily decreased to approximately 290 kPa. Although the WOR was not 100, the run was terminated after injecting 4.65 PV as the oil production began to level off. One of the major differences between this run and previous runs is the slow increase in water-oil ratio. Reservoir model sand samples were collected after the completion of the run. Oil saturations showed no particular trend along the well, as shown in Figure 9, and were higher near the injector consistent with previous observations. Overall oil saturations resembled those found for a thicker reservoir using Aberfeldy sand in Run 2.

Run 5: Effect of Shale Breaks

Oil reservoirs often contain shale beds known as shale breaks. It is believed the shale breaks interrupt fluid flow to the well bore and reduce oil recovery. The effect of shale breaks translates into reduction in vertical permeability which has been known to reduce the productivity of horizontal wells under primary depletion. In order to investigate the effects of shale breaks on waterflooding performance, Run 5 was conducted with simulated shale breaks and Pikes Peak sand. The shale breaks were modeled by placing 0.16 cm thick viton sheets into the reservoir. Eight separate pieces totaling a volume of 93.4 ml (area 583cm^3 were randomly inserted into the sand during the packing of the model. Figure 10 presents the production and injection pressure data for Run 5. Similar to Run 4, oil and water were produced simultaneously from the start of the run. However, the breakthrough of the injection water was estimated to 0.38 pore volume of water injection. This value was comparable to that of Run 4. For this run, an ultimate oil recovery of 56.5% of the initial oil-in-place was recorded after 3.75 PV of fluid had been injected. The WOR fluctuated throughout the run with a maximum value of 76. The injection pressure varied over a range from 410 kPa to 330 kPa. The run was terminated when the oil production started to level off. This run showed that the presence of shale breaks improved oil recovery by waterflooding for two parallel horizontal wells, one at the top and one at the bottom of the reservoir.

Run 6: Effect of Vertical Fractures

Vertical fractures are known to be helpful in recovering oil with horizontal wells under primary production. However, in the case of waterflood, vertical fractures are likely to reduce production

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efficiency of horizontal wells due to quick communication between injection and production wells. In order to investigate the effect of vertical fractures, Run 6 was conducted with Pikes Peak sand. In this Run, vertical fractures were simulated by thin plates separated by microspacings. Figure 11 shows the results of this Run. As can be seen in this figure, ultimate recovery was only 36% of the IOIP which was considerably poorer than any other run. The presence of vertical fractures led to quick water breakthrough. Once a channel was established, water bypassed most of the oil in place and led to a quick rise in water-oil ratios.

Run 7: Shale Breaks with Small Diameter Injection Well

Runs 7 and 8 were conducted to investigate the effects of injection well diameters. Aberfeldy sands were used for both of these runs. The injection oil used for these was a blend of Aberfeldy oil and kerosene. The blend was prepared in such a way that the final oil viscosity was around 770 mPa.s. Both Runs 7 and 8 were conducted with random distribution of simulated shale breaks. A model thickness of 6.6 cm representing a reservoir thickness of 6.6 m was used in both the runs. For Run 7, a 0.170 cm inside diameter injection well was used. This diameter corresponds to a field diameter of 17 cm (7"), while the producer was 0.774 cm diameter (30" field scale). Recovery and injection pressure performance of this run are shown in Figure 12. As can be seen from this figure, the injection pressure increases rapidly after an initial decline. Such a increase in pressure may be caused by flow restrictions in the wellbore region. However, as the displacement test continued, injection pressure declined in a manner analogous to Run 5. This behavior is expected once a communication between injection and production well has been established. Indeed, water breakthrough took place as the injection pressure was reaching a low value. The oil production continued after water breakthrough with continually increasing water-oil ratios. There was fluctuation in the WOR. However, this did not have much effect on the injection pressure. Ultimate oil recovery for this run was 21.3% after 3.08 pore volumes of water injection. After the run was stopped, sand and fluid samples were collected for Dean Stark analysis in order to determine residual saturations along the length of the injection and production wells. These values are shown as a function of dimensionless lengths of the injection and production wells in Figure 13. As can be seen in this figure, there appears to be slightly higher sweep from the middle section of the injection and production wells.

Run 8: Shale Breaks with Large Diameter Injection Well

Run 8 was identical to Run 7 except that a larger 0.774 cm diameter injection well representing a field diameter of 77.4 cm (30") was used. Recovery and injection pressure performance are

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depicted in Figure 14. As can be seen in this figure, the initial rise in injection pressure, as observed in Run 7, is absent from this run. Also, producing water-oil ratio was lower in this case. For the large well diameter case, the injection front is more uniform and leads to delayed water breakthrough. Consequently, the ultimate oil recovery in this case was almost twice as much as in Run 7 (with small injection well diameter). After completion of the run, sand and fluid samples were collected for the measurement of residual fluid saturations. These results are shown in Figure 15.

3.2 Waterflooding Reservoirs with a Bottom-Water Zone

Runs 9 through 13 were conducted in order to investigate the feasibility of waterfloods in heavy oil reservoirs containing a bottom-water zone. Runs were conducted with various parameters, such as water-to-oil zone thickness ratio, heterogeneity, etc. In all these runs, water was injected through a horizontal well placed close to the bottom-water zone. This strategy was thought to be effective in displacing oil by a gravity-stabilized water front.

Run 9: Oil-to-Water Zone Thickness Ratio of 5:1

Run 9 was the first experiment conducted to investigate the effects of bottom water thickness on production. For this particular run, an oil-to-water zone thickness ratio of 5:1 was used. The presence of a bottom-water zone led to almost instantaneous breakthrough of water. Unlike previous cases, the injected water can reach the bottom water within a few millimeters. Once, the communication has been established, water preferentially goes into the water zone following to least resistance to flow. During this process, a considerable amount of oil is produced. Also, since the production well was placed at the top of the reservoir, injected water displaced oil before reaching the production well through the oil zone. Results of Run 9 are depicted in Figure 16. As can be seen from this figure, the producing water-oil ratio remained high (around 10) but stable throughout the first two pore volumes of water injection. During the displacement test, an ultimate oil recovery of 24.8 percent of the oil in place was registered. Figure 17 depicts the results of the Dean Stark analysis of residual oil saturations. This graph shows that oil saturation was relatively uniform along the injection and production wells. Also, samples from the bottom-water zone were collected and analyzed for residual oil saturation. It was observed that the bottom water layer remained virtually 100 % saturated with water.

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Run 10: Oil-to-Water Zone Thickness Ratio of 1:1

This run was identical to Run 9 with the exception of the bottom water layer. For this run, the oil-to-water zone ratio was 1:1. Recovery and injection pressure performance of this run are shown in Figure 18. The producing water-oil ratio was very high right from the beginning of the displacement test. However, similar to Run 9, the WOR values were stable. Consequently, some oil was produced. By the end of the run, a final recovery of 8.1% was registered. This value, even though very low in absolute terms, represents quite high recovery since heavy oil reservoirs containing such a thick bottom-water zone are considered to produce no oil under primary depletion. Residual oil saturations are shown in Figure 19. The results of this run are similar to that of Run 9 in that oil saturation was quite uniform along the horizontal and injection wells. Similarly the bottom water had no oil present.

Run 11: Oil-to-Water Zone Thickness Ratio of 10:1

The third bottom water run was performed using a bottom- water-to-oil-zone thickness ratio of 10:1. Recovery and injection pressure performance of this run are depicted in Figure 20. Contrary to previous two runs with bottom water, this run showed unstable water-oil ratio values. Also, this was the first case for which the bottom water showed the presence of oil. It appears that part of the displaced oil ended up in the bottom-water zone. Note that the injection well of was placed further away from the bottom water zone and injected water could not enter the bottom- water zone directly. Therefore, injected water displaced the oil which, in turn, displaced a part of the bottom-water zone. As a consequence, regions near the production well showed much higher residual oil than the regions near the injection well. An ultimate recovery of 22.8 % IOIP was registered in this run. Observation of final oil saturations in Figure 8 reveal that the bottom water had been partially saturated with oil during the water flood stage. Another important observation that can be made from this graph is that the final saturations along the injection and production wells were non-uniform. This may have been caused by the larger reservoir resistance caused by the larger oil pay zone layer. This postulate is supported by the increase in injection pressures.

The ultimate effect of the larger reservoir resistance is that larger differential pressures were developed along the injection well, thus creating a non-uniform moving water front.

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Run 12: Oil-to-Water Zone Thickness Ratio of 5:1 with the Addition of Shale Breaks

Run 12 was conducted in order to examine the effect of shale breaks with bottom water. Since the 5:1 oil-to-bottom-water thickness ratio yielded the highest oil production, this ratio was considered to be optimum. Consequently, it was used for bottom water runs thereafter.

Shale breaks were modelled using 8 pieces of 5 cm x 7.5 cm and 5 mm thick viton sheets. This run yielded substantially lower ultimate % IOIP production than the run with just bottom water. Figure 22 depicts the recovery and injection pressure performance of Run 12. As can be seen from this figure, water-oil ratio was unusually high right from the beginning of the displacement test. Also, considerable fluctuation in WOR was observed. Final recovery of this run was only 8.1% of the oil-in-place. Residual oil saturations are shown in Figure 23. This figure reveals a relatively uniform oil saturation along the production and injection wells. The bottom water layer was partially saturated with oil, particularly on the injection side. This can be rationalized by the water flood zone being deflected downward into the bottom water by the shale breaks.

Run 13: Oil-to-Water Zone Thickness Ratio of 5:1 with Vertical Fractures

Similar to Run 12, Run 13 also used an oil-to-water zone thickness ratio of 5:1.

Vertical fractures were simulated using ten pairs of thin brass alloy plates. The two plates were placed directly adjacent to each other thus creating a simulated fracture.

The results of this run yielded an ultimate oil recovery of 5.7% with 3.17 pore volumes injected. Figure 24 depicts the recovery and injection pressure performance of Run 13. Final oil saturations indicate that oil was being pushed into the bottom water layer by the waterflood. The saturation plots are shown in Figure 25.

3.3 Waterflooding with Vertical/Horizontal Well Combination

Run 14: Vertical Injector with Horizontal Producer

Run 14 was conducted with a combination of a vertical injector and a horizontal producer. For this run the initial oil saturation was 88.6 percent. This saturation value was somewhat lower than that of any other runs with horizontal injector and horizontal producer. This is understandable because the vertical well was used as an injector for saturating the model with oil. Saturating the model

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with a combination of vertical and horizontal wells may not be as efficient as horizontal injector and horizontal producer. Figure 26 depicts the oil recovery and injection pressure performance of Run 14. For this run, the water breakthrough took place after the production of 15% of the initial oil in place. This breakthrough time was longer than any of the previous runs with the same thickness. At the end of the displacement test, as much as percent oil in place was recovered in this run. However, during the initial stages, the injection pressure was higher than any of the previous cases. In a field perspective, this may be indicative of injectivity problems in heavy oil reservoirs.

3.4 Waterflooding with Vertical Injector and Vertical Producer: 770 mPas Oil

Run 15 was conducted with vertical injector and vertical producer. This was considered to be the base case comparable to existing field set-ups. The vertical wells were placed at the corners of the rectangular model and the displacement test was carried out diagonally to model 1/4 of a five spot pattern. Figure 27 shows the recovery and injection pressure curves of Run 15.

4.0 EXPERIMENTAL RESULTS AND DISCUSSION

Fifteen displacement tests were carried out to study various effects of water flooding heavy oil reservoirs using horizontal wells. The experimental procedure for each run is described in the previous section. The following analysis focuses on comparing the various parameters tested during this experiment.

4.1 Reservoirs Without Bottom Water

4.1.1 Effect of Well Diameter

4.1.1.1 Production Well

To satisfy scaling criteria for the model, two different diameter production wells were tested (0.774cm and 0.17cm). The smaller of the two wells (0.17cm) satisfied scaling criteria better than the larger well (Islam, 1988). However, it was uncertain if the smaller well would be able to sustain a constant fluid flow and yield a pressure drop along its length equivalent to that in the field. Some of recent studies have indicated the need of having a larger diameter in order to ensure unrestricted flow (Ong and Butler, 1989). In this study, we decided to use proper scaling

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factor for the well diameter in order to scale the wellbore effects more appropriately. Therefore, the first two runs were conducted to investigate the adequacy of small well diameter and to investigate the effect of larger well diameters. It was decided that on the basis of these two runs, to use realistic production well diameters for the rest of the experimental runs. Injection pressure curves for Runs 1 and 2 are shown in Figure 28. As can be seen in the figure, small well diameter shows clearly the effects of wellbore flow restriction in the production well (higher injection pressure). However, with the small diameter the flow through the horizontal well does not seem to be plugged. In fact, this smaller diameter shows smaller oscillations in injection pressure curve. The large well diameter, even though lower in overall magnitude, does show unstable injection pressure behavior. The reason for such behavior is not clear. However, this may be an indicative of the invasion of virgin reservoirs with alternating communication with the production well. Figure 28 was instrumental in deciding to use the smaller diameter (0.17 cm) for the production well throughout the rest of the runs. Recovery curves of Runs 1 and 2 are compared in Figure 29. An overall oil recovery of approximately 37% was attained in both runs but the smaller well required 70% more injection fluid to do so. The larger well allowed the same fluid recovery in 60% of the time the smaller well did. An earlier breakthrough was observed in the case of smaller production well. In the case of small production well, the initial form of the displacement front is likely to be tongue like because the production well does not act as a line source due to increased pressure drop along the length of that well. Therefore, even though the production horizontal well is open to a producing pressure of say, 35 psi, there will be an increasing producing pressure along the length of the horizontal well due to the pressure drop within it. Therefore, the highest pressure drop will form diagonally between projector and producer, and a tongue-like, rather than uniform, water front will be formed. Such a front is likely to cause water breakthrough much earlier than that caused by a uniform front. Figure 30 compares breakthrough recoveries for various cases (using two horizontal wells except where labelled otherwise). It is clearly shown that water breakthrough has strong dependence on production well diameter. The asymmetric flow caused by the pressure drop developed along the production well is clearly important.

Results of Runs 1 and 2 determined that the smaller well could yield a suitable amount of fluid flow for the experimental model and the smaller diameter was used for production wells in subsequent runs.

4.1.1.2 Injection Well

Runs 7 and 8 were performed in order to investigate the role of injection well diameters. Note that in all other runs without a bottom-water zone the large injection well diameter was used. This was

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done in order to simulate a uniform front without wellbore effects. However, it was felt important to investigate the effects of injection well diameter. Runs 7 and 8 were both equipped with small diameter production wells. However, Run 7 had the smaller injection well diameter. Figure 31 compares the recovery curves of these two runs up to 3.2 pore volumes of water injection. The transient high pressure peak (Figure 32) observed in the small injector case may reflect local plugging which leads to localized channelling. It is clearly shown that a small diameter of the injection well introduced earlier water breakthrough. The final saturations obtained from Run 8 with the large injection well suggest that the front was moving in a uniform fashion in this case. The consequence of early breakthrough is a much poorer oil recovery by the small diameter injection well. Once, a water channel is created between the injection and production wells it is difficult for the injected water to invade new regions which offer much higher resistance to flow. The injection pressures of Runs 7 and 8 are compared in Figure 32. Interestingly, injection pressures do not differ very much apart from the presence of initial peak in for the small well diameter case. Once communication is established profiles are expected to be similar. Injection wellbore flow restrictions contribute to only early breakthrough and recovery performances rather than overall injection pressure behavior.

4.1.2 Effect of Oil Viscosity

Run 3 was conducted with an oil viscosity of 6040 mPa.s. This run was similar to Run 2 except for the oil viscosity. Hence, a comparison between Runs 2 and 3 should give insight into the effects of oil viscosity on waterflooding with horizontal wells. Figure 33 compares oil recovery curves of these two runs. As can be seen in this figure, higher viscosity oil leads to earlier water breakthrough. A comparison of breakthrough recoveries is also made in Figure 30 for different cases. It is well known that high mobility ratio causes earlier water breakthrough. However, there is no correlation of residual oil saturations with oil viscosity. This effect is evident in Figure 33. After water breakthrough, the higher mobility ratio run continues to produce with a lower and more stabilized water-oil ratio. Consequently, the oil recovery of the higher oil viscosity run catches up to that of the lower oil viscosity run. In this particular case of horizontal well, final recovery of both viscosity oils appear to be similar for all practical purposes.

Figure 34 compares injection pressures of Runs 2 and 3. Initial pressure is very high for the high oil-viscosity case. Such a high injection pressure might be a crucial factor in field application since it leads to very low injectivity. However, the injection pressure declines sharply following the water breakthrough. The injection pressure in fact levels off to a value close to that of Run 2 (770

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mPa.s oil). After the water breakthrough, a water channel between the injection and production wells is established. Therefore, the injection pressure is no longer dominated by the oil viscosity.

4.1.3 Effect of Reservoir Thickness

Runs 2 and 4 were conducted to investigate the feasibility of a waterflood for two different reservoir thicknesses. Reservoir thickness of 10.00 cm and 3.35 cm were used to investigate the effect of thickness on oil recovery and injection pressure. These values correspond to field thicknesses of 10 m and 3.35 m, respectively. Figure 35 compares the recovery curves of Runs 2 and 4. For the case of vertical well injection, these two curves should give the same oil recovery (in dimensionless form). However, for the case of horizontal wells, fluid distribution may be different from that of a linear core, and the sweep efficiency may be affected by the thickness of the reservoir. The thickness appears to play a role in determining water breakthrough as shown in Figure 35. Note that the spacing of the both runs is the same. However, the thickness-to-spacing ratio is different for these two cases. This may lead to different vertical sweep. Also, the cross sectional area of the displacing front is much smaller for the smaller thickness case. This has implications on the width of the fingers as well as onset and propagation of fingers.

Figure 36 compares injection pressures of Runs 2 and 4. The thicker reservoir shows slightly higher injection throughout the displacement test. This higher pressure may be simply due to higher distance between the injection and production wells in the thicker reservoir case. In terms of water injectivity, thickness of the reservoir should not create any additional problem.

4.1.4 Effect of Reservoir Heterogeneity

Reservoir heterogeneity is an integral part of heavy oil reservoirs which show the presence of shale breaks or high permeability channels. The presence of this heterogeneity may alter the waterflooding performance considerably. Runs 5 and 6 were conducted to investigate the effects of reservoir heterogeneity, such as the presence of shale breaks and vertical fractures.

4.1.4.1 Effect of Shale Barriers

Sand reservoirs are often accompanied by shale breaks. Run 5 was conducted to investigate the effects of shale breaks on oil recovery by waterfloods. Results of this run is compared with Run 4 which was conducted under similar conditions as in Run 5 except that shale breaks were present in Run 5. Figure 37 compares recovery performance of Runs 4, 5 and 6. Run 6 was conducted in

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the presence of vertical fractures. It can be seen from Figure 37 that the water breakthrough is slightly delayed in the presence of shale breaks. The overall implication of shale breaks is the reduction of vertical permeability. Even though such a reduction leads to poor oil recovery under primary depletion conditions, this is likely to homogenize the displacement front to make it more uniform in the present case. This would decrease the severity of finger formation in the vertical direction, thus delaying the water breakthrough. Oil recovery with the shale breaks was 56.5% IOIP or 4.9% higher than without the shale breaks. It appears that the post breakthrough performances of the two runs are very similar. Consequently, the recovery curves appear to be shifted only.

Figure 38 compares the injection pressures of Runs 4 through 6. Injection pressure with shale breaks is slightly higher than the homogeneous case. Such behavior is expected from the vertical permeability considerations alone. However, the injection pressure is never too high to warrant any special consideration in terms injectivity during a waterflood with horizontal wells.

4.1.4.2 Effect of Vertical Fractures

Even though engineering intuition indicates that oil recovery with horizontal wells is higher in the presence of vertical fractures (high k_v/k_h) during primary depletion with horizontal wells, this is not the case for a displacement- type recovery mechanism, such as, waterflooding. In order to investigate the effects of vertical fractures, Run 6 was conducted with simulated vertical fractures. Figure 37, which compares recovery curves of Runs 4, 5, and 6, indicates that in the oil recovery was the lowest in the presence of vertical fractures. These fractures caused quick communication between injection and production wells and established continuous water channel. This caused early water breakthrough. Even after breakthrough, the fractures maintain open communication between injection and production wells. This leads to minimal oil recovery throughout the displacement test.

Results of Run 6 confirmed that reservoirs with vertical fractures are not good candidates for horizontal well implementation under waterflood conditions.

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4.2 Reservoirs With Bottom Water

4.2.1 Effect of Bottom Water Thickness

Three runs, Runs 9 through 11 were conducted to investigate the feasibility of waterflooding in heavy oil reservoirs containing various sizes of bottom water. Oil-to-water zone thickness ratios, h_o/h_b, of 1:1, 5:1 and 10:1 were used for Runs 9 through 11, respectively. Oil recovery results of these runs are compared in Figure 39. The case of oil-to- water zone thickness ratio of 1:1 gives the lowest recovery. The injected water goes into the bottom-water zone due to low resistance too flow from the water zone. This leads to quick communication of the injection and production wells through the bottom-water zone and the oil zone remains poorly swept. However, since the production well was not placed immediately on top of the bottom-water zone, oil was displaced during passage of the injected water from the bottom-water zone to the production well. Consequently, some oil was produced and at the end of the displacement test, as much as 7 percent oil-in-place was produced. Even though this appears to be a meagre amount, note that heavy oil reservoirs containing bottom-water zones are known to produce less than 1% oil in place under primary depletion. For higher oil-to-water zone thickness ratio values, oil recovery is considerably higher. Beyond a h_o/h_b value of 5, the oil recovery appears to be rather insensitive to h_o/h_b values; however, the larger diameter injection well was used in Run 9 (h_o/h_b = 5) which might contribute to increased recovery in this case. Alternately, this result may be explained as follows. A thin bottom water zone leads to higher oil recovery due to the presence of low water saturation at the production end. However, a thin bottom water layer also offers high resistance to water flow. This leads to a decline in water injectivity. Oil recovery is a result of these two phenomena. Since these two phenomena are counteracting, the resultant leads to an optimum bottom water thickness. Such an optimum was previously observed by Islam (1987) and Proctor et al. (1987). In the tests performed, the water flood was most effective in the presence of an oil-to-water ratio zone thickness ratio of 5:1 for which the reservoir resistance was optimum. As the reservoir pay zone increased to a 10:1 ratio, resistance increased to a point where excessive fingering occurred and total oil production decreased (also explaining the increase in injection pressure).

Figure 40 shows the injection pressure curves for Runs 9 through 11. As it appears in this figure, injection pressures are very similar for all the cases with slightly increasing injection pressure as the oil-to-water zone thickness ratio was increased. Since most of the fluid movement was through the bottom-water zone, it is expected that the injection pressure will be dominated by the thickness of the bottom- water zone.

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4.2.2 Effect of Reservoir Heterogeneity with Bottom Water

Runs 12 and 13 were conducted to investigate the effects of reservoir heterogeneity, such as the presence of shale breaks and vertical fractures. Initial investigation showed that shale breaks improved oil recovery performance whereas the presence of vertical fractures decreased oil recovery considerably in reservoirs without a bottom-water zone.

4.2.2.1 Effect of Shale Breaks with Bottom Water

It is believed that shale breaks tend to delay water break- through, thus enhancing oil recovery. Run 12 was conducted with an oil-to-water zone thickness ratio of 5:1 and in the presence of shale breaks. Results of this run are compared with those of Runs 10 (homogeneous with bottom water) and 13 (with vertical fractures) in Figure 41. Interestingly, the presence of shale breaks decreased oil recovery as can be seen in Figure 41. In the presence of a bottom-water zone the oil displacement takes place from the bottom to the top where the production well is located. Since the injected water has higher density than the oil, it is likely that severity of viscous fingering will be diminished through gravity stabilization. Such a displacement process is disrupted by the presence of shale breaks and is likely to worsen the frontal sweep. Consequently, water breakthrough took place earlier than expected and the ultimate oil recovery was low.

Figure 42 compares injection pressures for Runs 10, 12, and 13. It is evident that reservoir heterogeneity does not control the injection pressure.

4.2.2.2 Effect of Vertical Fissures with Bottom Water

Vertical fissures acted as water channels in the oil pay zone, thus, leading to very early water breakthrough. Run 13 was conducted to investigate the effects of vertical fractures. As can be seen in Figure 41, the oil recovery was reduced drastically with the addition of vertical fissures. The bottom water reservoir with vertical fissures yielded less recovery than bottom water with shale breaks and much less than that of the homogeneous case.

4.3 Combination of Vertical and Horizontal Wells

Run 14 was conducted to explore the possibility of using a vertical injector in conjunction with a small diameter horizontal producer. In this run, the vertical injector was located at the corner of

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the model with horizontal well producing from the other side. The prototype for this case was 10 m thick. Figure 43 compares recovery performance of Runs 14 and 2. Both these runs were conducted with the same size of horizontal producers and an oil viscosity of 770 mPa.s. However, vertical injector was used for Run 14 as opposed to horizontal injector. As can be seen in Figure 43, water breakthrough is delayed in Run 14. This is followed by higher oil recovery throughout the test. As a consequence, over 15% more oil is recovered in Run 14. Figure 44 compares injection pressures of the two runs. This figure indicates that the injection pressure is considerably higher in the vertical injector case until water breakthrough. Following water breakthrough, injection pressures become similar for both cases. Evidently, after water channel is established between the injector and the producer, injection pressure is no longer dominated by the injection pattern.

Figures 45 and 46 compare recovery and injection pressure curves of Run 14 with those of Run 1. Run 1 was conducted with large diameter production well. These figures indicate that, even with a large diameter of the production well, the vertical injector and horizontal producer combination yields the best results.

4.4 Vertical Injector and Vertical Producer

Run 15 was conducted to model the base case of a vertical injector with a vertical producer. Figure 47 compares recovery of this run with Run 1 for which horizontal injector was used with a horizontal producer. It can be seen from this figure that the water breakthrough takes place quite late for the horizontal injector/horizontal producer case. Consequently, recovery is much higher for this case. However, following breakthrough, recovery profiles appear to be similar, through offset, in both cases. Figure 48 compares the injection pressures of Runs 1 and 15. Due to much smaller area of injection, injection pressure is much higher during initial stages of the displacement test for the vertical case. The difference in injection pressures is less after water breakthrough. This behavior is expected since injection area does not play a major role after a water communication path has been established.

4.5 Overall Comparison

Figure 49 compares recovery at 1 PV of water injection for various cases. It appears that the best recovery technique is with vertical injector and horizontal producer. Also, in the absence of a bottom-water zone, oil recovery is quite high in the presence of shale breaks. The presence of fractures makes all the cases perform very poorly. In the range of oil viscosities studied, viscosity

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change does not affect oil recovery to great extent. The presence of even a thin bottom-water zone decreases oil recovery drastically.

5.0 NUMERICAL SIMULATION

Numerical simulation of the scaled model tests was carried out using NHRC multi-domain horizontal well simulator.

5.1 Simulator Parameters

Field dimensions which are scaled up values of the laboratory model were used. The geometric configuration is shown in Figure 50. Note that one quarter of the injection and production wells was used due to symmetry of flow. Initial saturations and porosity were set equal to the model values. A water injection rate of $4m^3$/day was used. Permeability was intimated to be 10 Darcies. Relative permeability curves were obtained from previous history matching exercises of primary and bottom water drive of some heavy oil reservoirs. These curves are shown in Figure 51.

5.2 Numerical Simulation Results

Numerical simulation runs were carried out without any change to the model. Figure 52 compares recovery results obtained from numerical simulation with results of Run 1. Results agree remarkably well, especially in breakthrough time. Figure 53 compares injection pressures of the numerical and experimental runs. Even though numerical values are slightly higher throughout, the curves show very similar trend.

Numerical simulation of bottom water cases having 10m oil pay zone thickness underlain by a 5m water zone (h_o/h_b = 2) under the same conditions gave ultimate recoveries of 13 to 15% IOIP while a case with h_o/h_b = 1 gave about 8% IOIP. These are consistent with ultimate recoveries cited in Table 1 and Figure 49 for the physical model Runs 9-11.

6.0 SUMMARY AND CONCLUSIONS

A series of scaled model experiments was conducted to explore the potential of waterflooding heavy oil reservoirs with horizontal wells. Initial runs showed the effectiveness of a small well diameter (0.17 cm) for proper modelling horizontal wells. The well allowed fluid flow with proper

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restrictions and fulfilled the most stringent scaling criteria attempted. A realistic diameter of the production well indicated the relative importance of pressure drop effects within the production well to modelling results. The diameter of the injection well had a more pronounced effect on oil recovery performance with a waterflood, but may have been due to transient plugging in the injector.

Oil viscosity had very little effect on oil recovery. Even though water breakthrough was delayed for the lower oil viscosity case, final recovery for 770mPa.s and 6040mPa.s were almost the same. However, recovery during the early stages was higher for the lower viscosity case.

Reservoir thickness had very little effect on injection pressure. The injection pressure of the thicker reservoir was approximately 10% greater than that of the thinner reservoir. Oil recovery for the thicker reservoir was more rapid. Greater amounts of oil were recovered with less injected fluid required than was required for the thin reservoir. However, the thin reservoir yielded 15% more of its IOIP displaying a better recovery factor.

Shale breaks had only minimal effect on oil recovery or injection pressure. Results from the experiments indicate a slightly higher oil recovery from the run with shale breaks. The presence of shale breaks delayed the water breakthrough.

An oil-to-water zone thickness ratio of 5:1 (oil pay zone:bottom water) was found to be the optimum for waterflooding thin reservoirs with bottom water layers.

Shale breaks in bottom water situations resulted in a 7% reduction in production.

Vertical fractures led to drastic reduction in oil recovery for reservoirs with or without a bottom-water zone.

The combination of vertical injector with horizontal producer gives the most efficient oil recovery. However, attaining injectivity may be a concern in this case.

Vertical injectors with vertical producers give distinctly lower recovery (less than 30%) than the horizontal/horizontal or vertical/horizontal schemes.

Limited numerical simulation results show surprisingly good agreement with experimental results given the use of relative permeabilities obtained by history matching field performance.

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8.0 TABLES

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TABLE 1: SUMMARY OF RESULTS

	RUN #1	RUN #2	RUN #3	RUN #4[1]	RUN #5[1]	RUN #6[1]
Prod. Well inside diameter (cm)	0.77	0.17	0.17	0.17	0.17	0.17
Injection Well inside diameter (cm)	0.77	0.77	0.77	0.77	0.77	0.77
Porosity %	38.8	36.3	36.7	37.3	36.5	38.6
Initial Oil Saturation	87.4	85.8	91.2	88.5	86.7	89.6
Oil Vis.mPa.s	770	770	6040	770	770	770
Reservoir Thickness (cm)	10	10	10	3.35	3.35	3.35
Bottom Water Thickness (cm)	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.
Oil Pay Zone Thickness (cm)	10	10	10	3.35	3.35	3.35
Ultimate %IOIP Recovered	38.1	36.6	32.4	51.6	56.5	35.8
Pore Volumes Injected	1.36	2.3	1.76	4.66	3.75	5.26
Recovery after 1 P.V. (%IOIP)	36	30	28	27	35	11
COMMENT	large producer		high viscosity	thin zone	+shale break	+vertical fracture/barrier

1. Pikes Peak sand used. Aberfeldy sand was used in all other runs.

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Table 1 cont'd...

PARAMETERS	RUN #7	RUN #8	RUN #9	RUN #10	RUN #11	RUN #12	RUN #13	RUN #14	RUN #15
Production Well inside diam.(cm)	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17
Injection Well inside diam.(cm)	0.17	0.77	0.77	0.17	0.17	0.17	0.17	0.77	0.77
Reservoir Porosity (%)	41.1	38.1	38.2	38.2	38.2	41.8	38.5	38.7	39.0
Inital Reservoir Oil Saturation (%)	98.5	89.2	89.1	95.4	93.1	96.5	95.6	88.6	92.0
Oil Viscosity (mPa.s)	750	750	770	770	793	732	752	770	770
Reservoir Thickness (cm)	6	6	6	6	6	6	6	10	10
Bottom Water Thickness (cm)	N.A.	N.A.	1	3	0.55	1	1	N.A.	N.A.
Oil Pay Zone Thickness (cm)	6	6	5	3	5.45	1	1	N.A.	N.A.
Ultimate % IOIP Recovered	21.3	40.2	24.8	8.1	22.8	8.1	5.7	40	25
Pore Volumes Injected	3.1	4.0	4.3	3.0	3.9	3.0	3.2	1.8	1.2
Recovery after 1 P.V. (% IOIP)	16	30	9	4	9	4	3	38	22
COMMENT	+ shale break + small injector	+ large injector	5:1	1:1	bottom water 10:1	5:1 + shale break	5:1 + vertical fracture/ barrier	vertical injector	vertical injector & producer

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9.0 FIGURES

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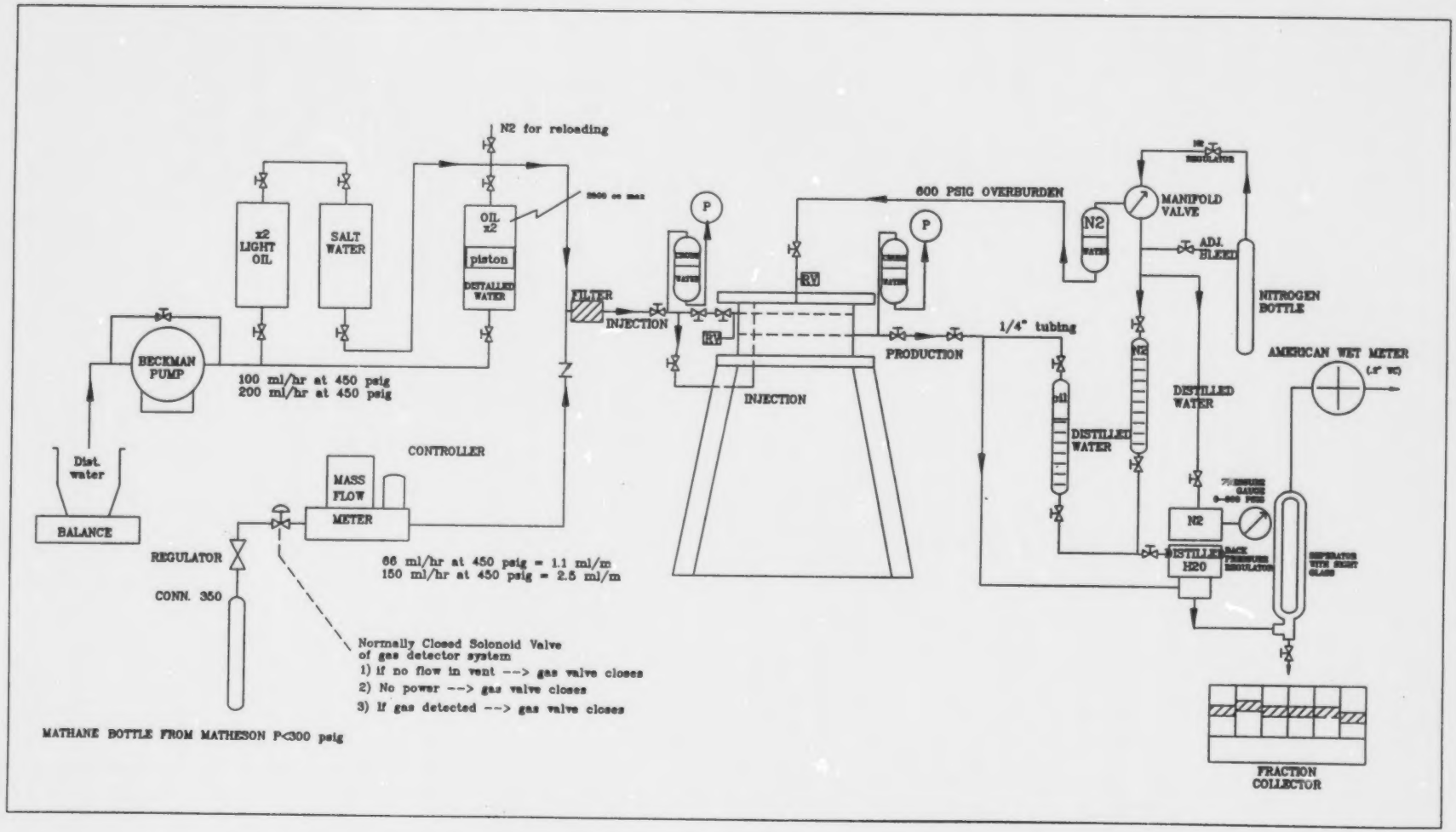

Figure 1. Schematic of the Experimental Setup

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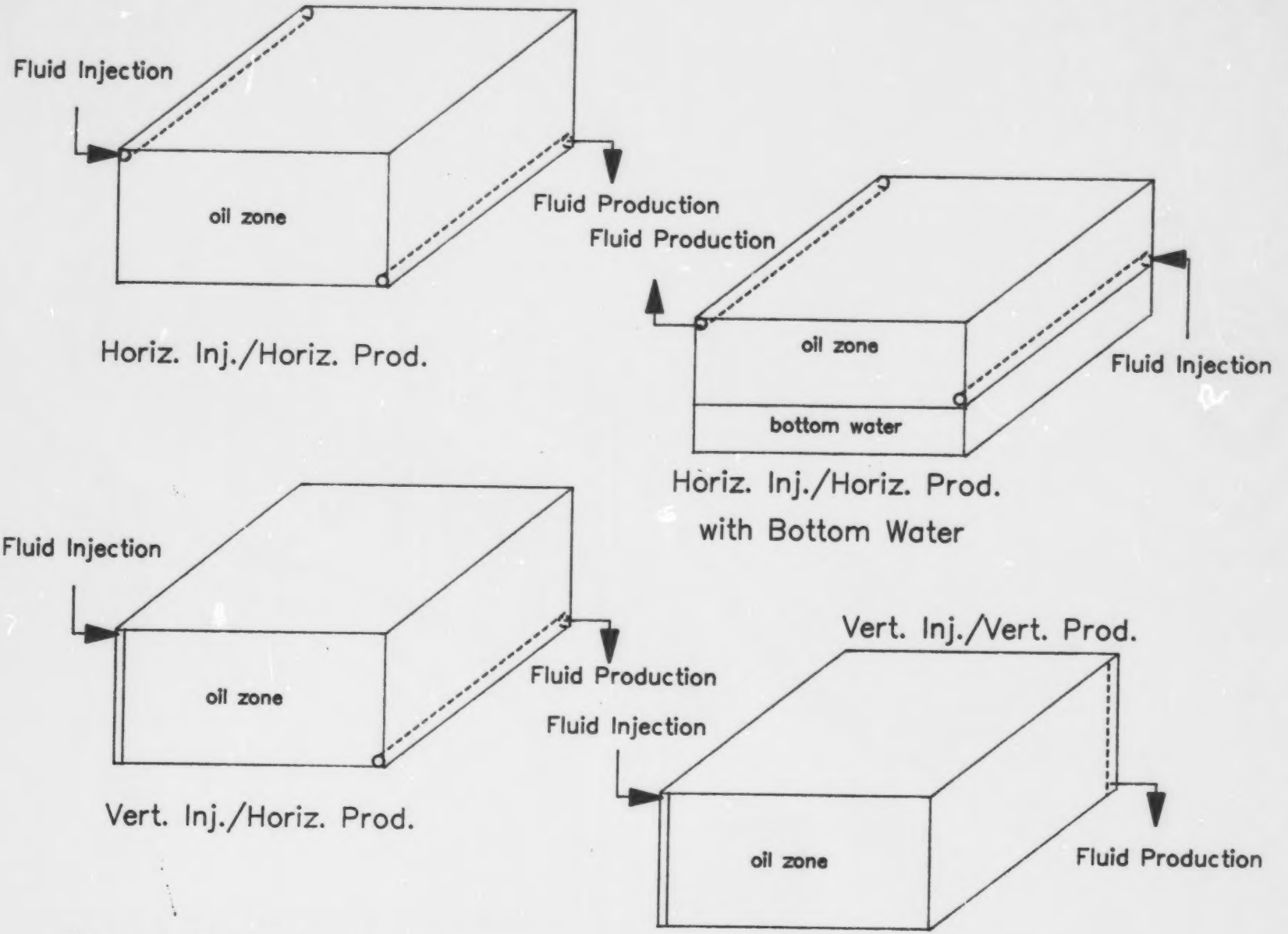

Figure 1b Well Configurations for Various Cases

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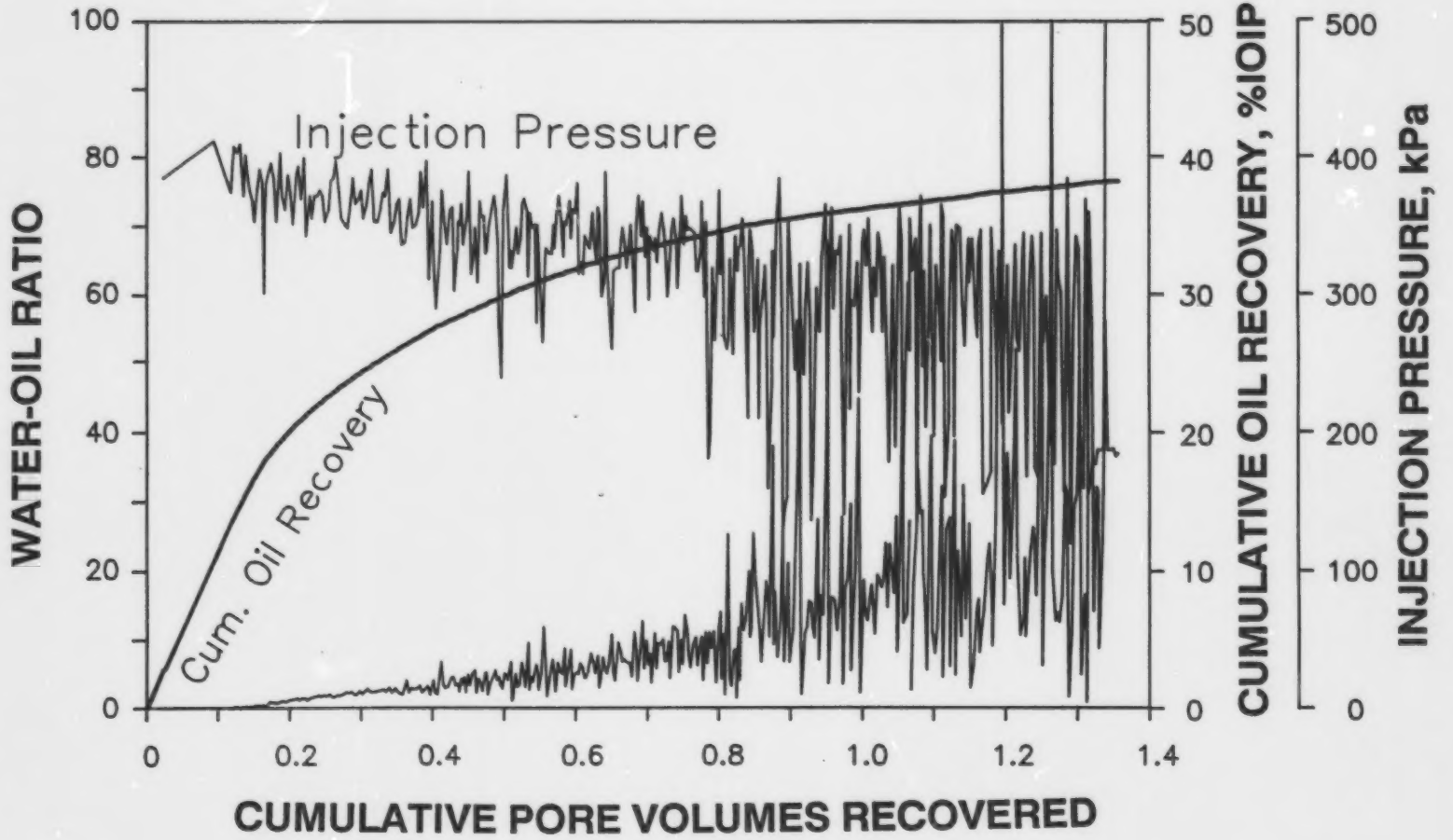

Figure 2. Recovery Performance of Run 1 (large prod. well diameter)

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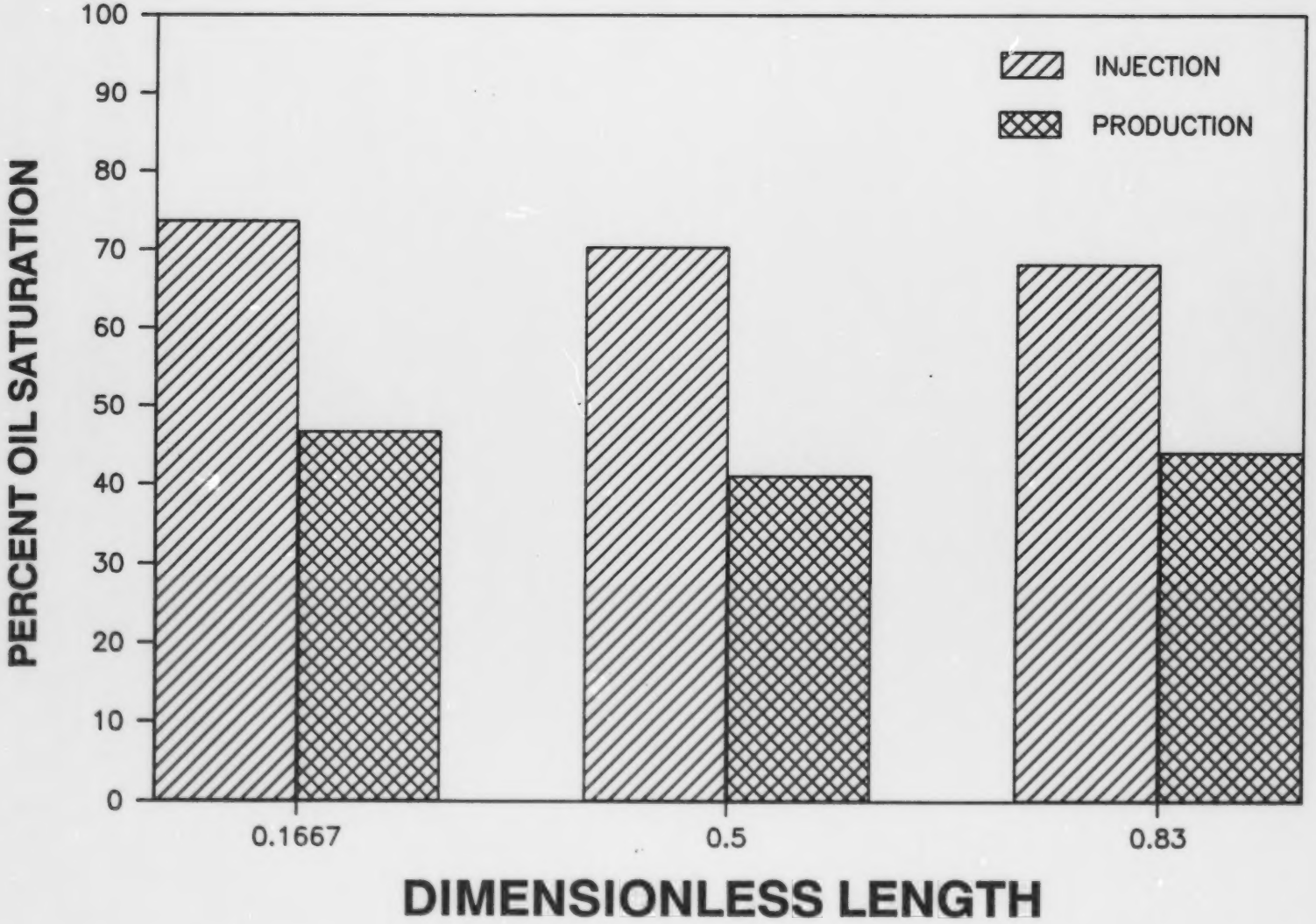

Figure 3. Final In Situ Oil Saturation of Run 1

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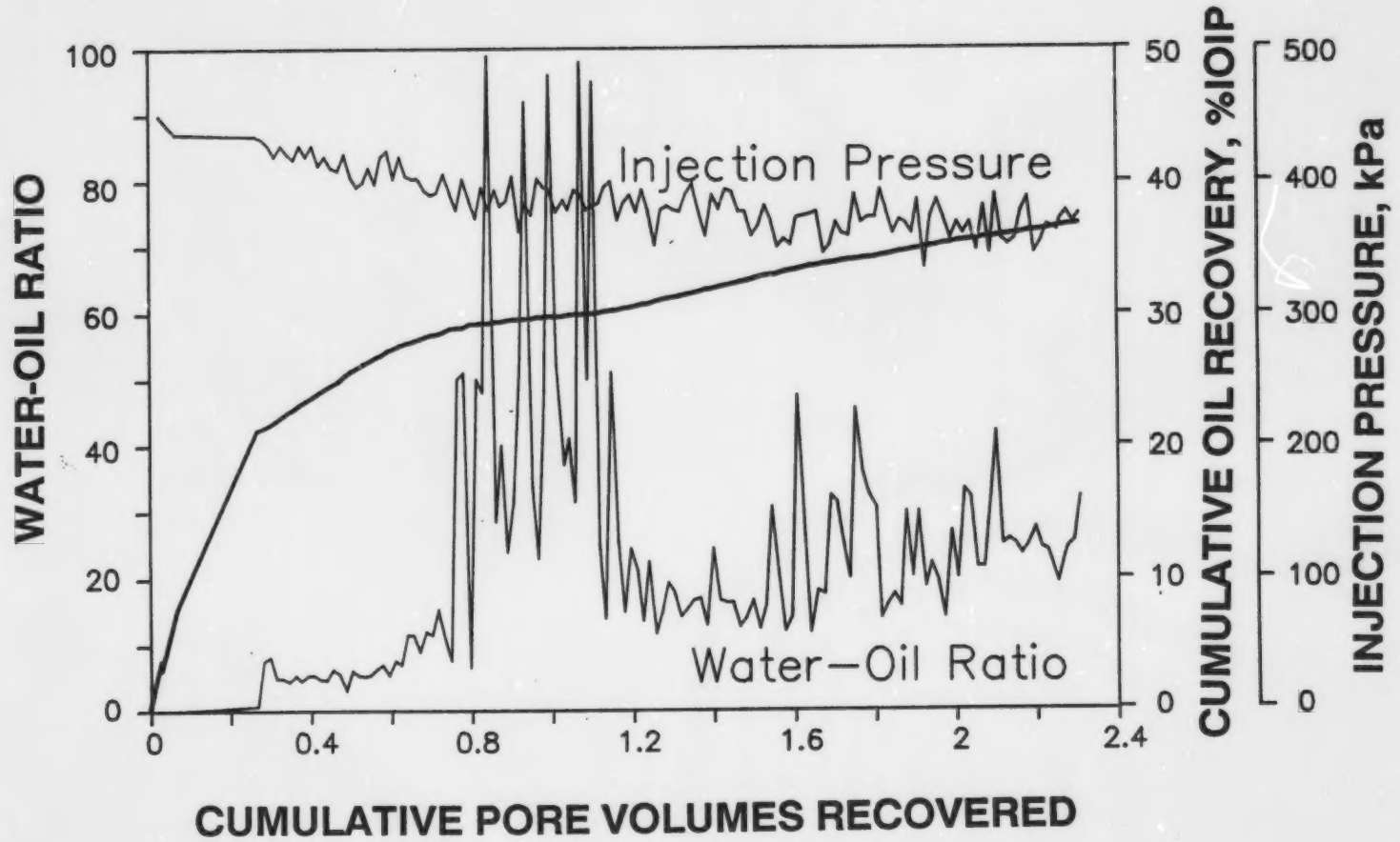

Figure 4. Recovery Performance of Run 2 (small prod. well diameter)

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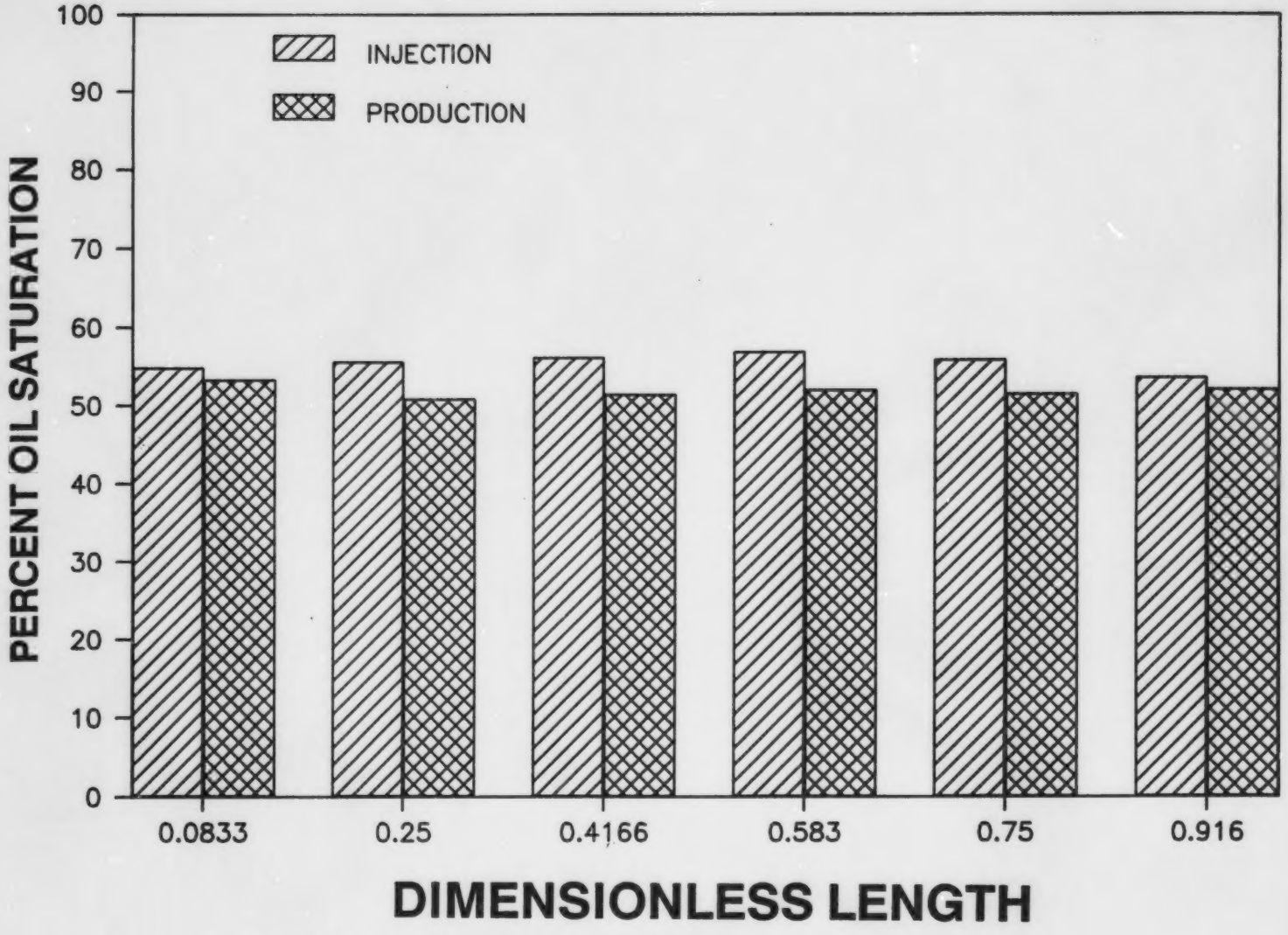

Figure 5. Final In Situ Oil Saturation of Run 2

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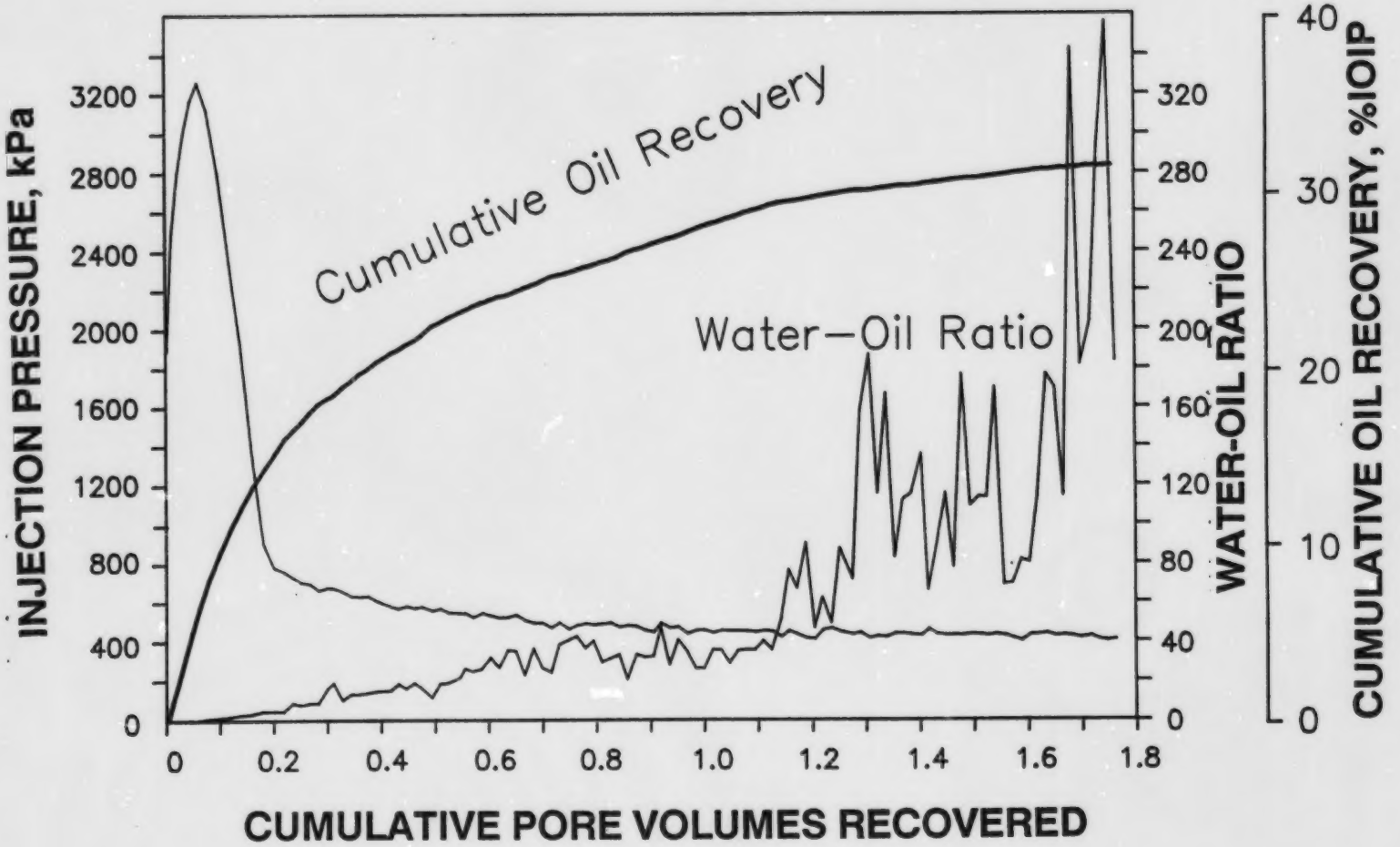

Figure 6. Recovery Performance of Run 3 (oil viscosity = 8,400 mPas)

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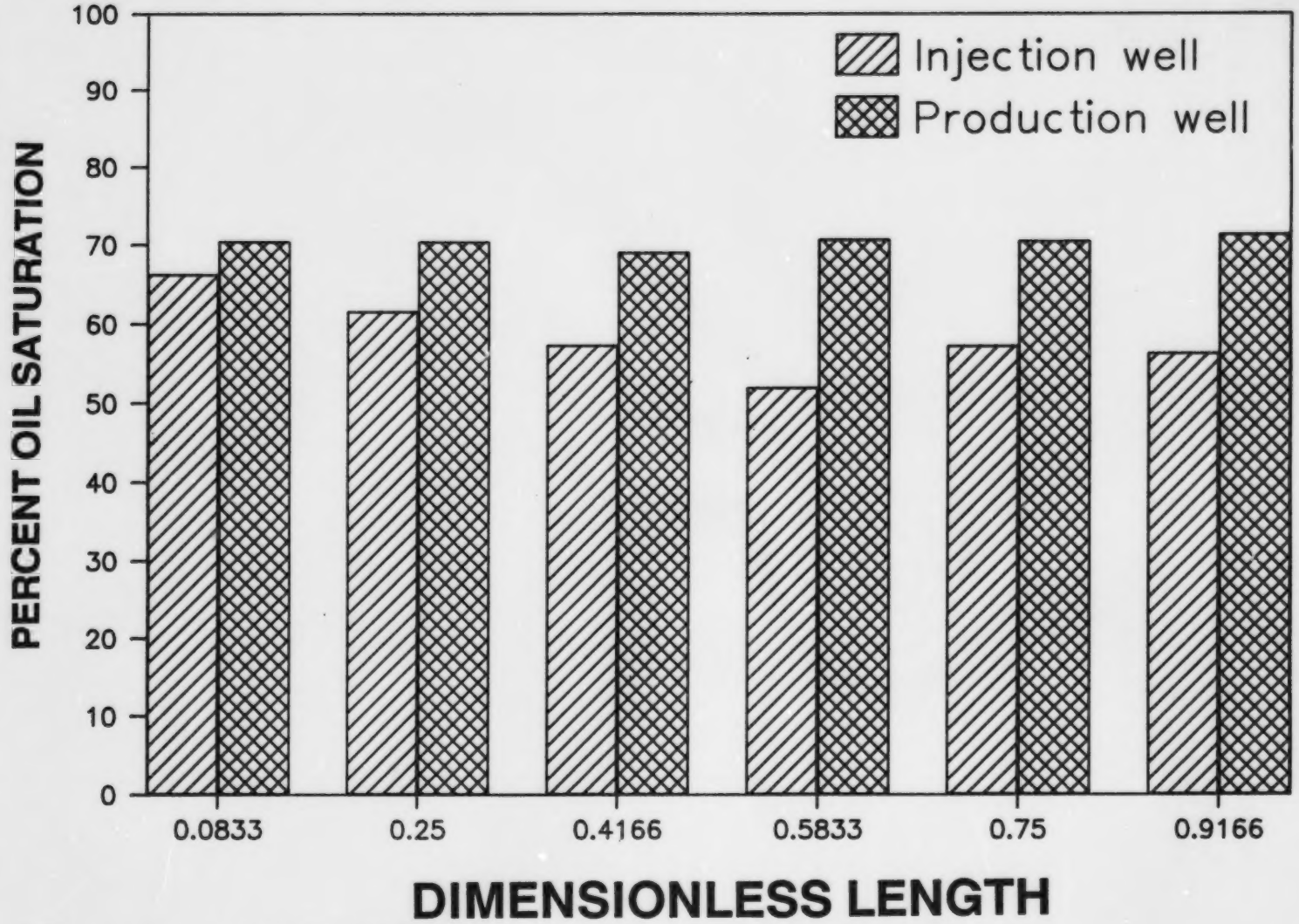

Figure 7. Final In Situ Oil Saturation of Run 3

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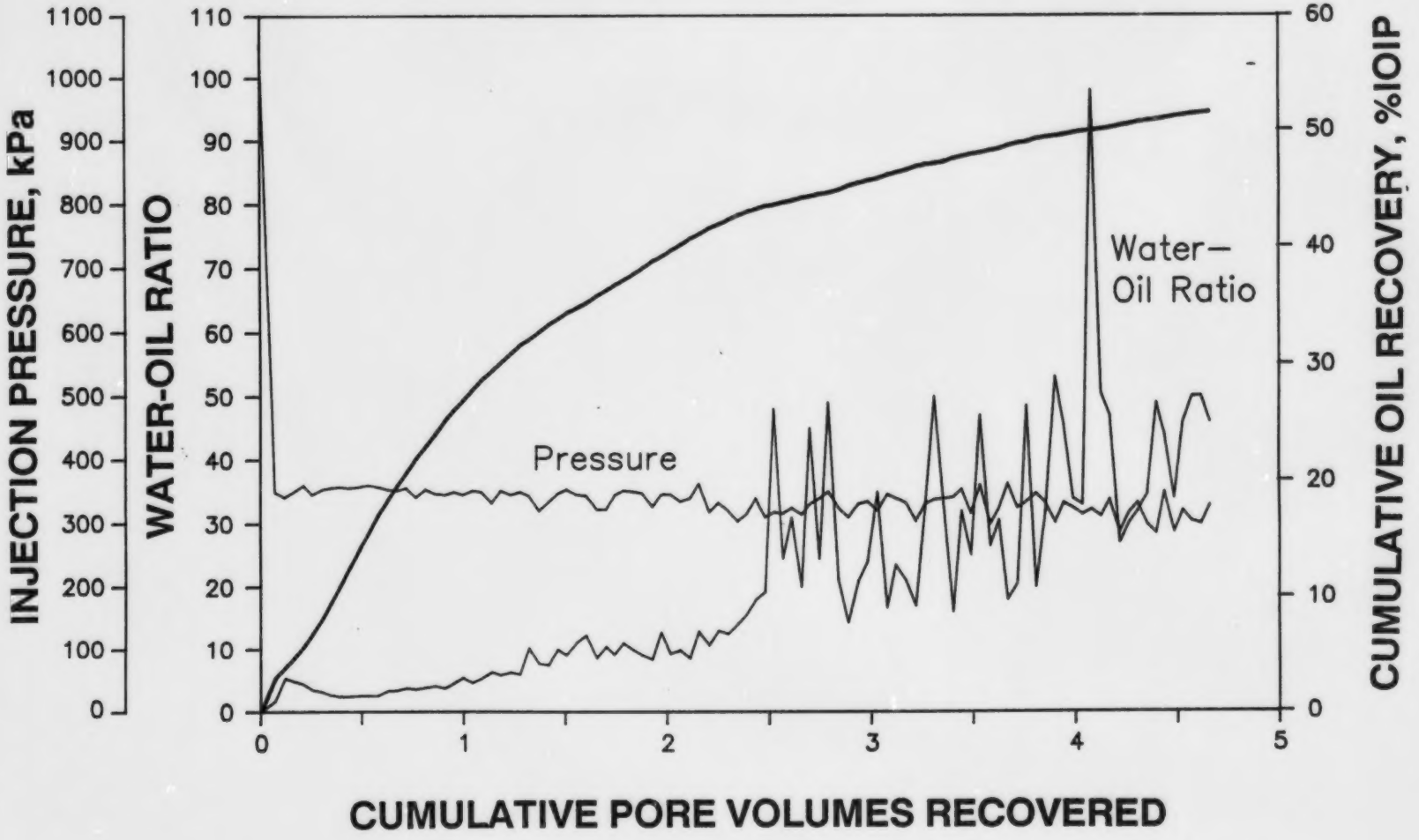

Figure 8. Recovery Performance of Run 4 (thin reservoir)

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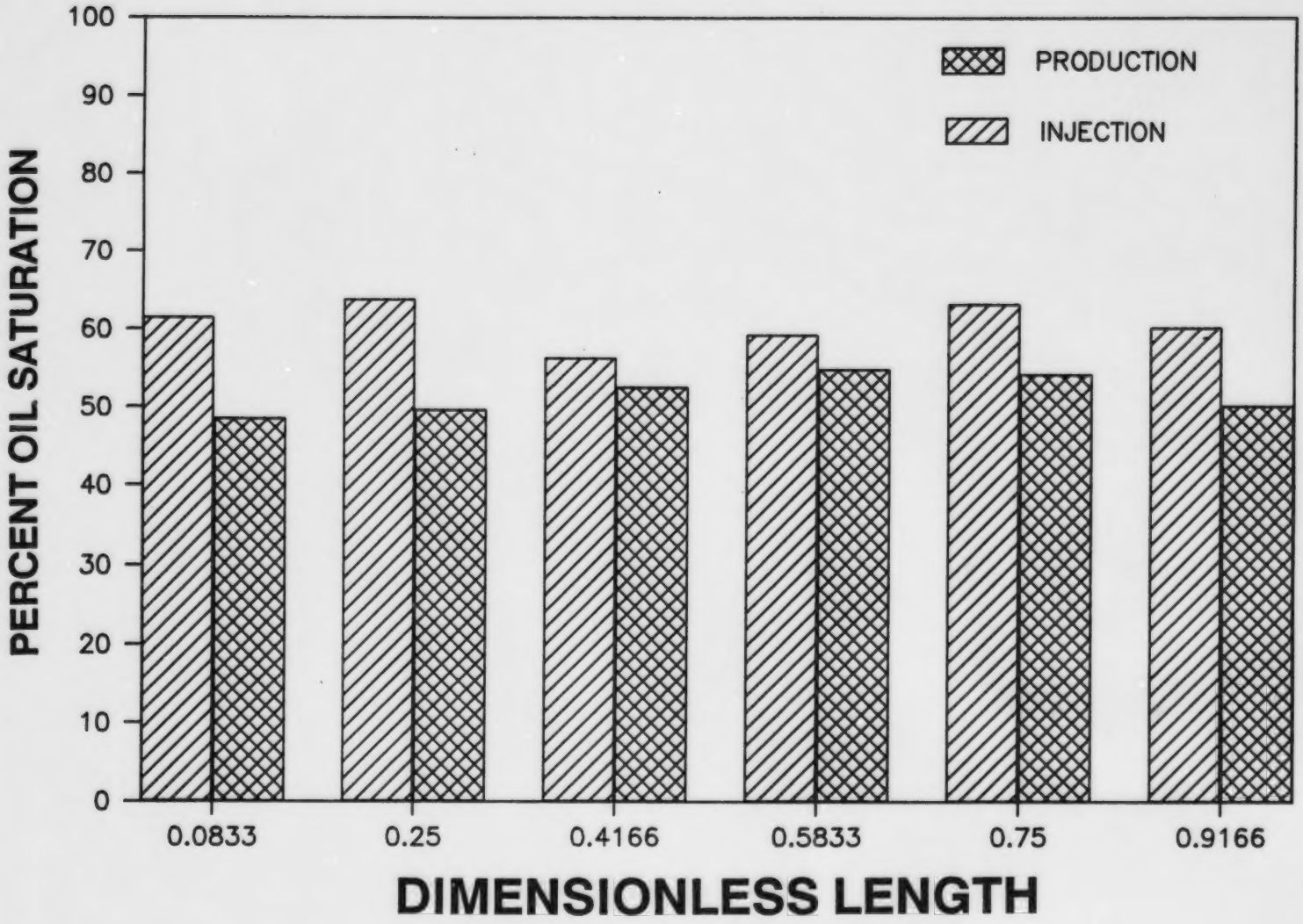

Figure 9. Final In Situ Oil Saturation of Run 4

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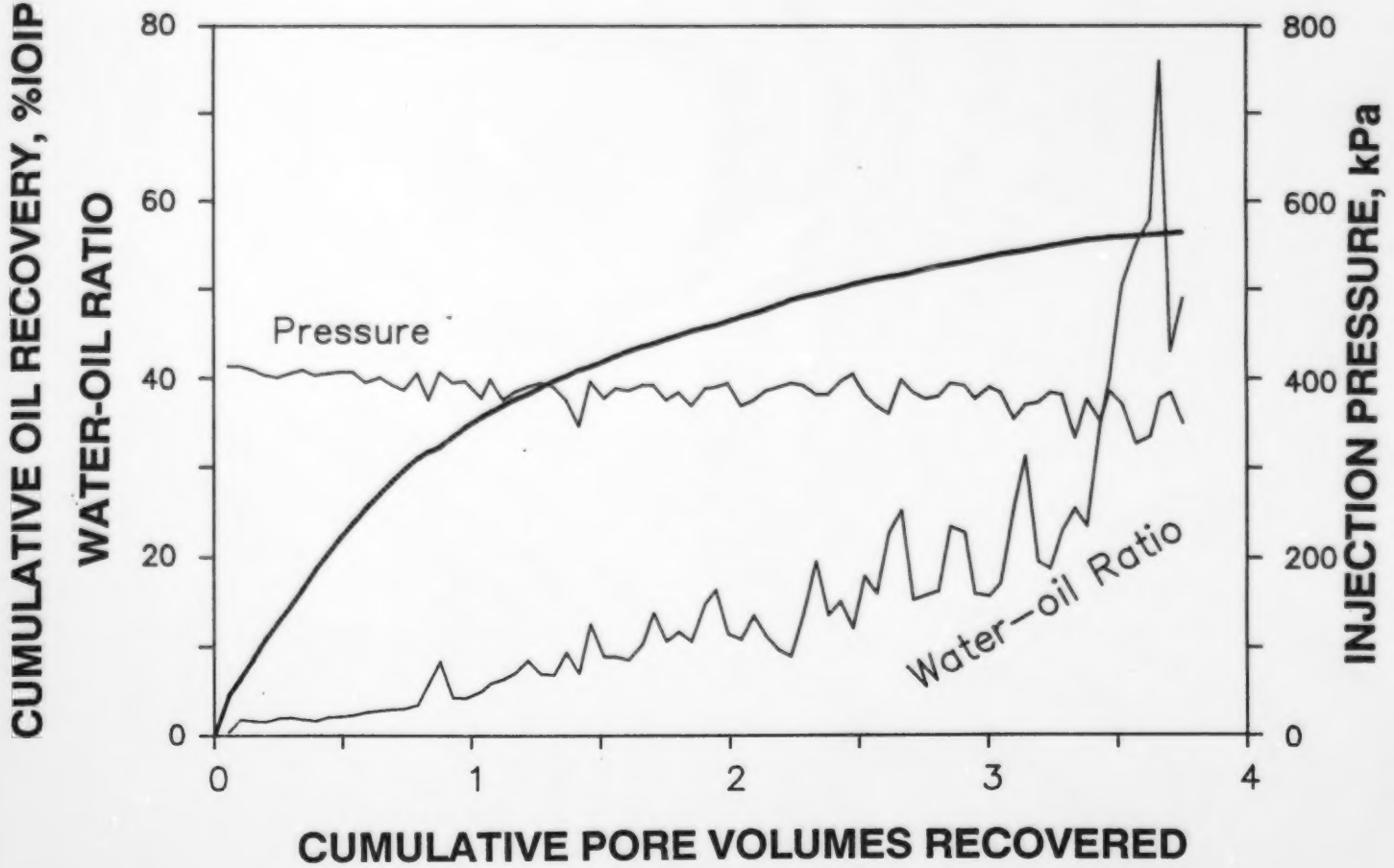

Figure 10. Recovery Performance of Run 5 (thin reservoir with shale breaks)

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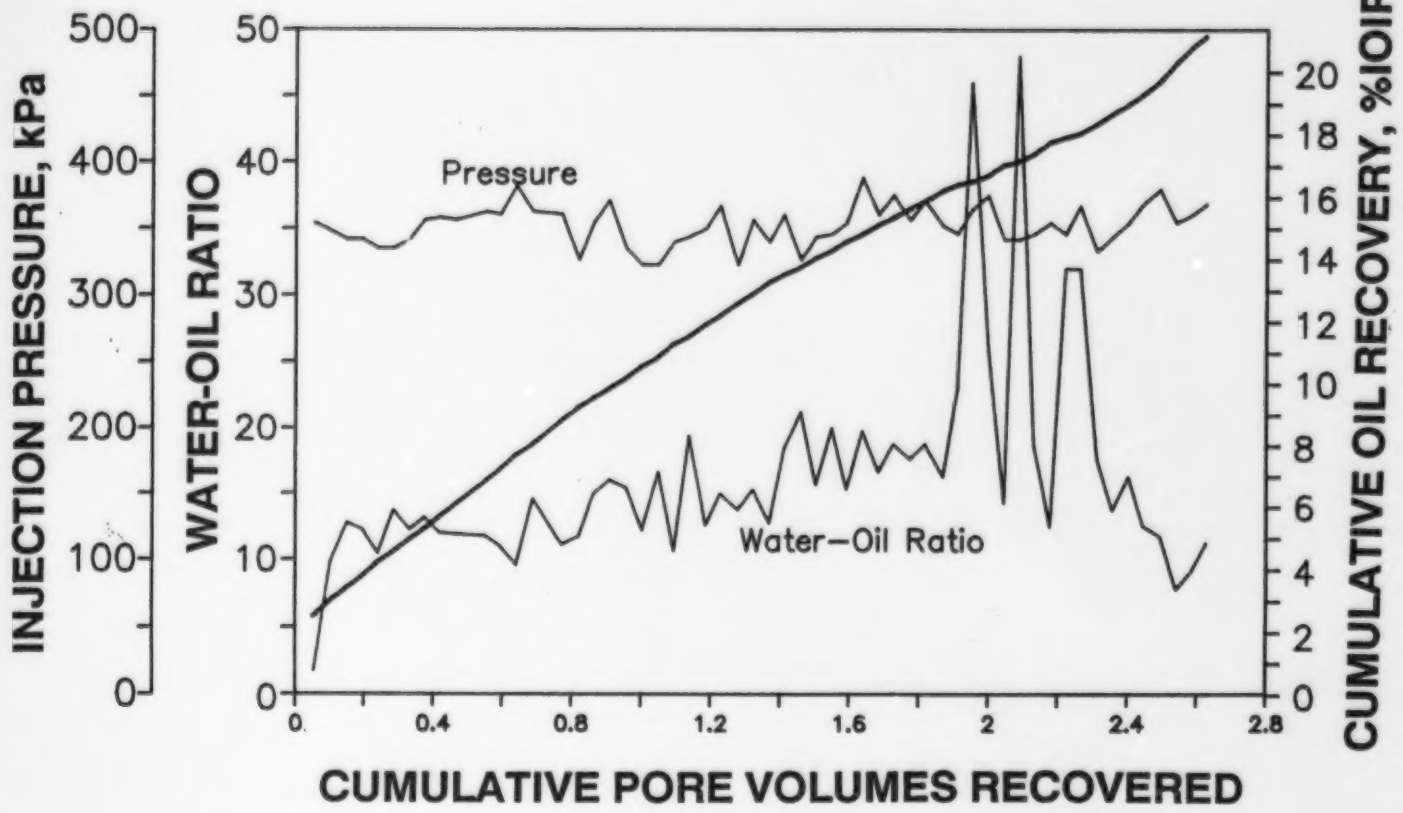

Figure 11. Recovery Performance of Run 6 (thin reservoir with vertical fractures)

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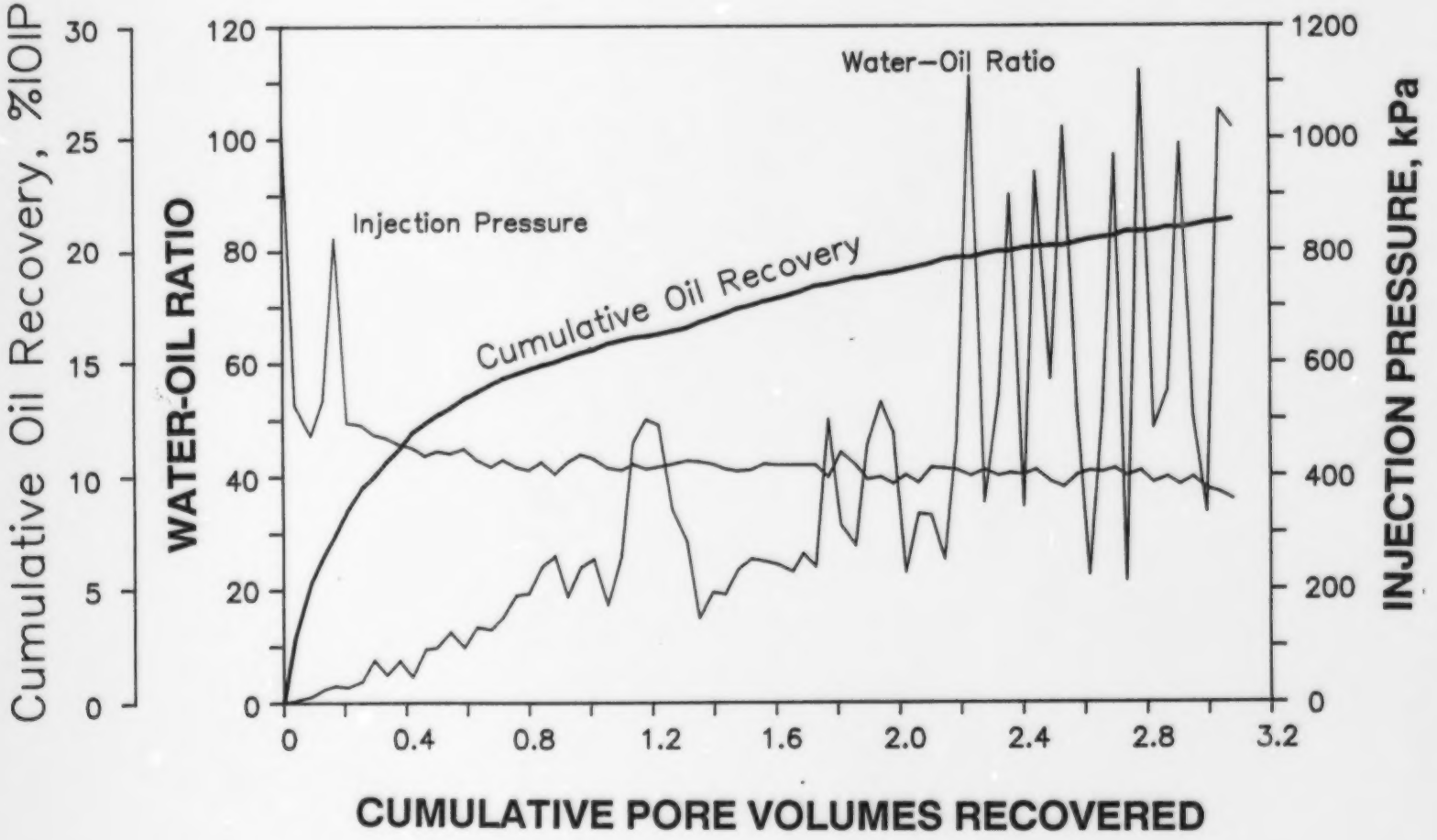

Figure 12. Recovery Performance of Run 7 (thin reservoir with shale breaks and small injection well diameter)

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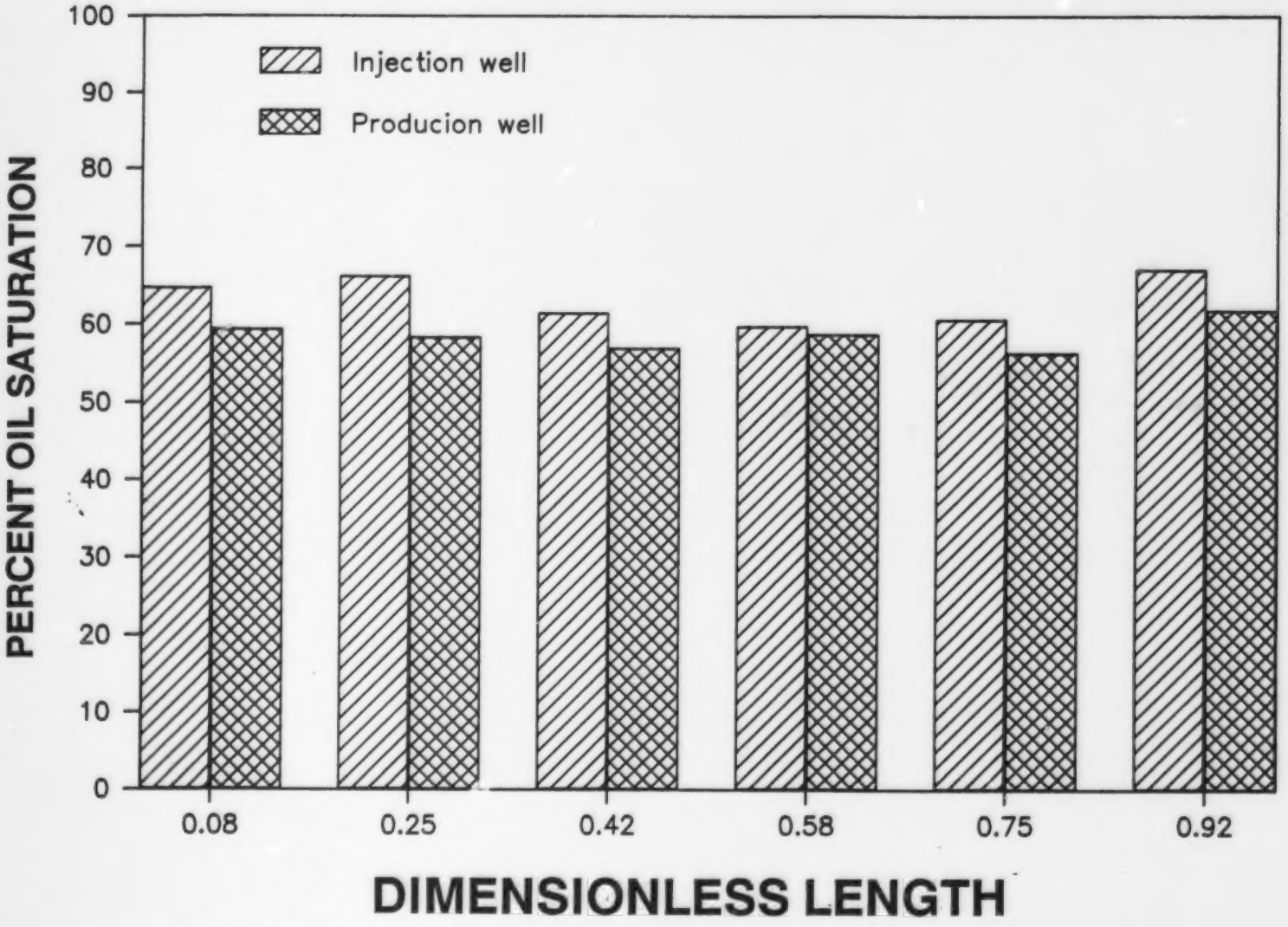

Figure 13. Final In Situ Oil Saturation of Run 7

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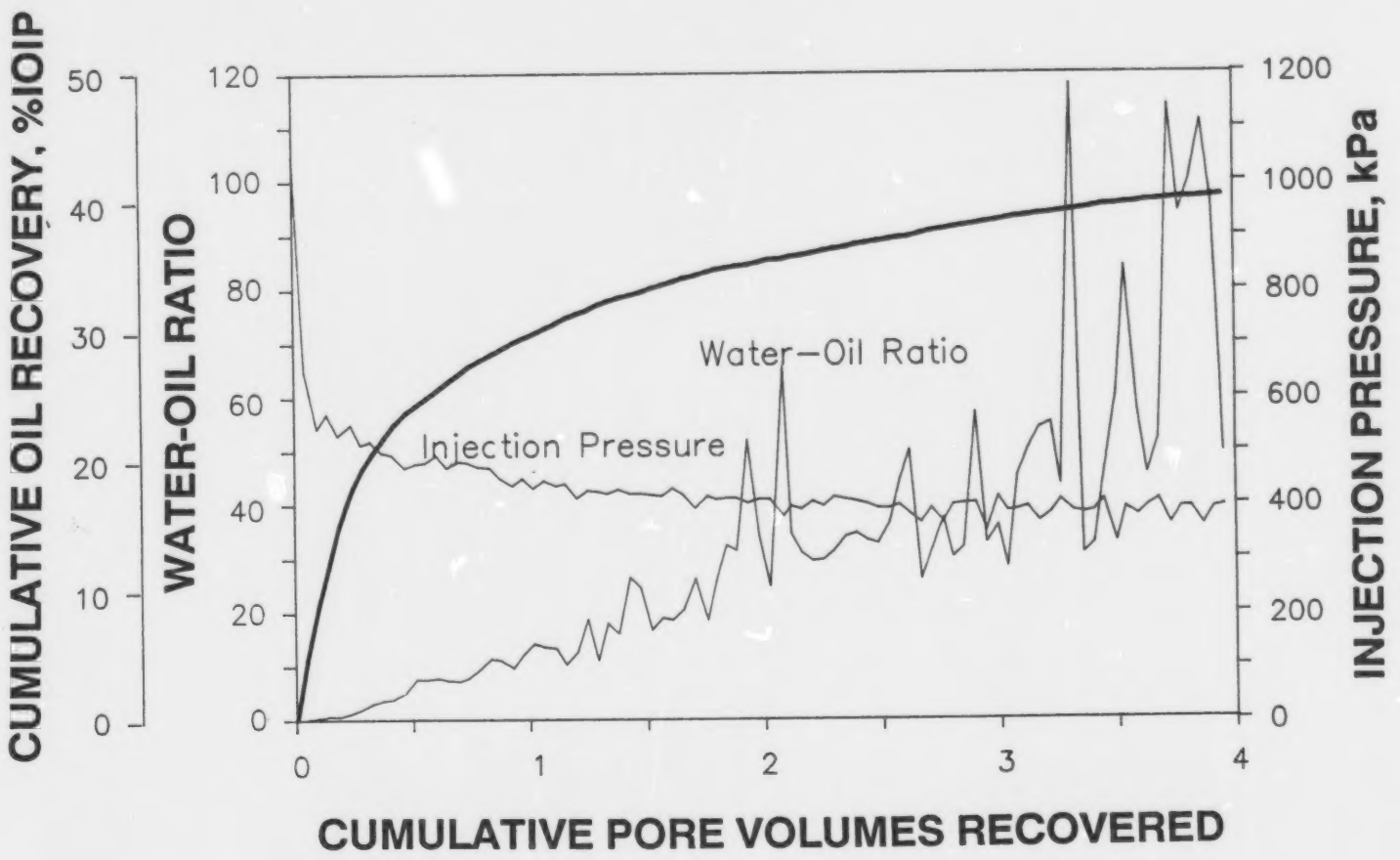

Figure 14. Recovery Performance of Run 8 (thin reservoir with shale breaks and large injection well diameter)

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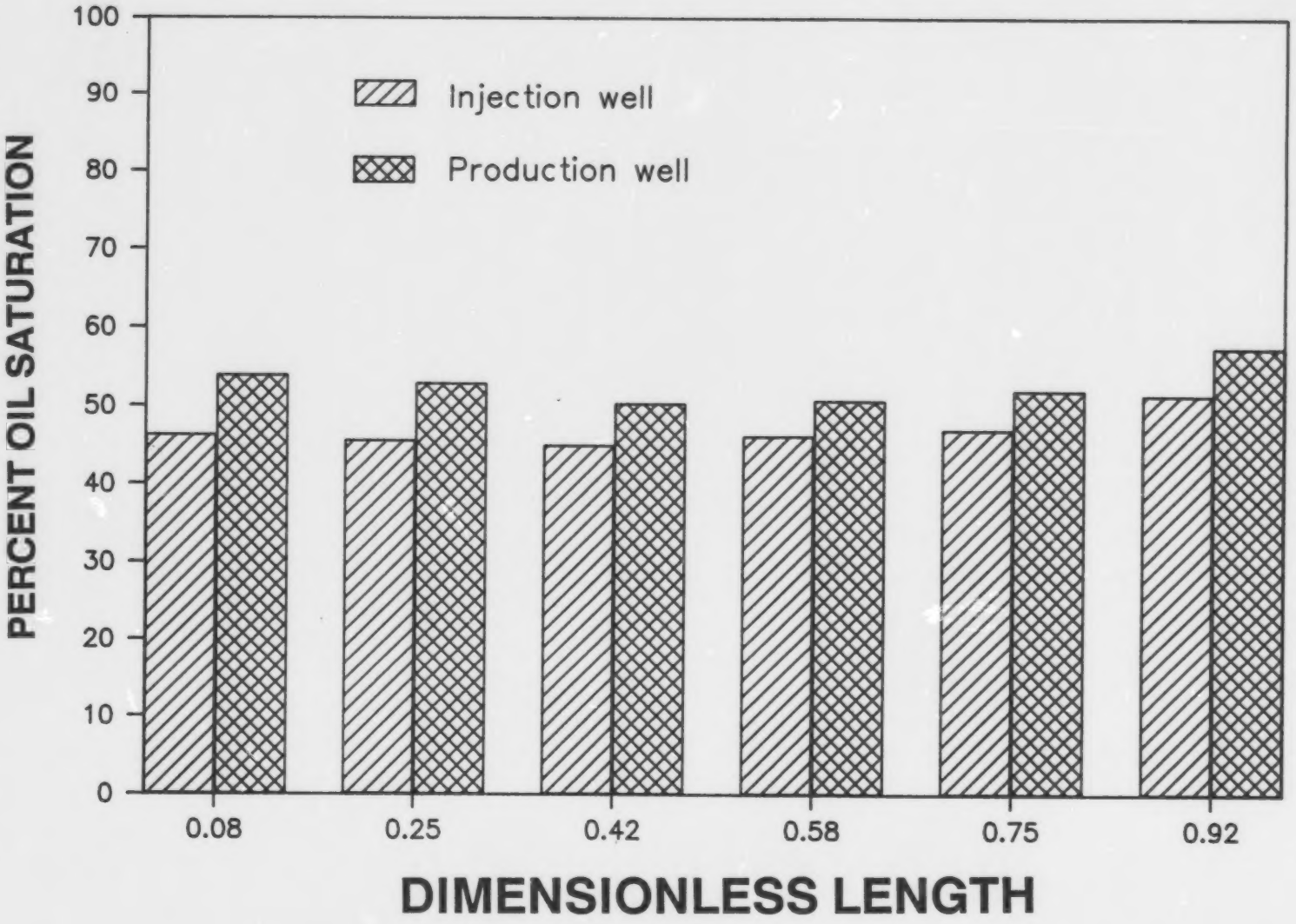

Figure 15. Final In Situ Oil Saturation of Run 8

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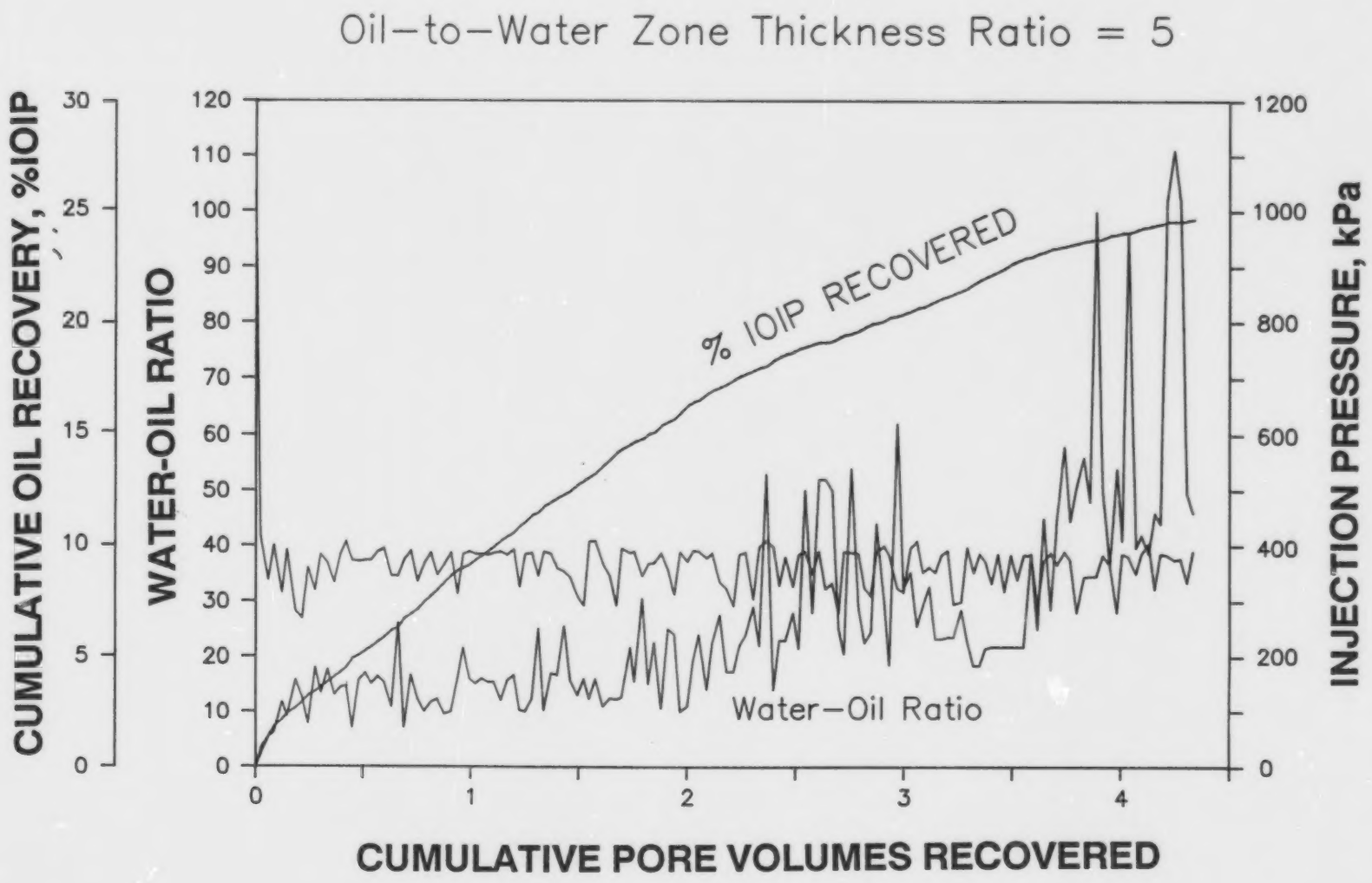

Figure 16. Recovery Performance of Run 9 ($h_o/h_b=5$)

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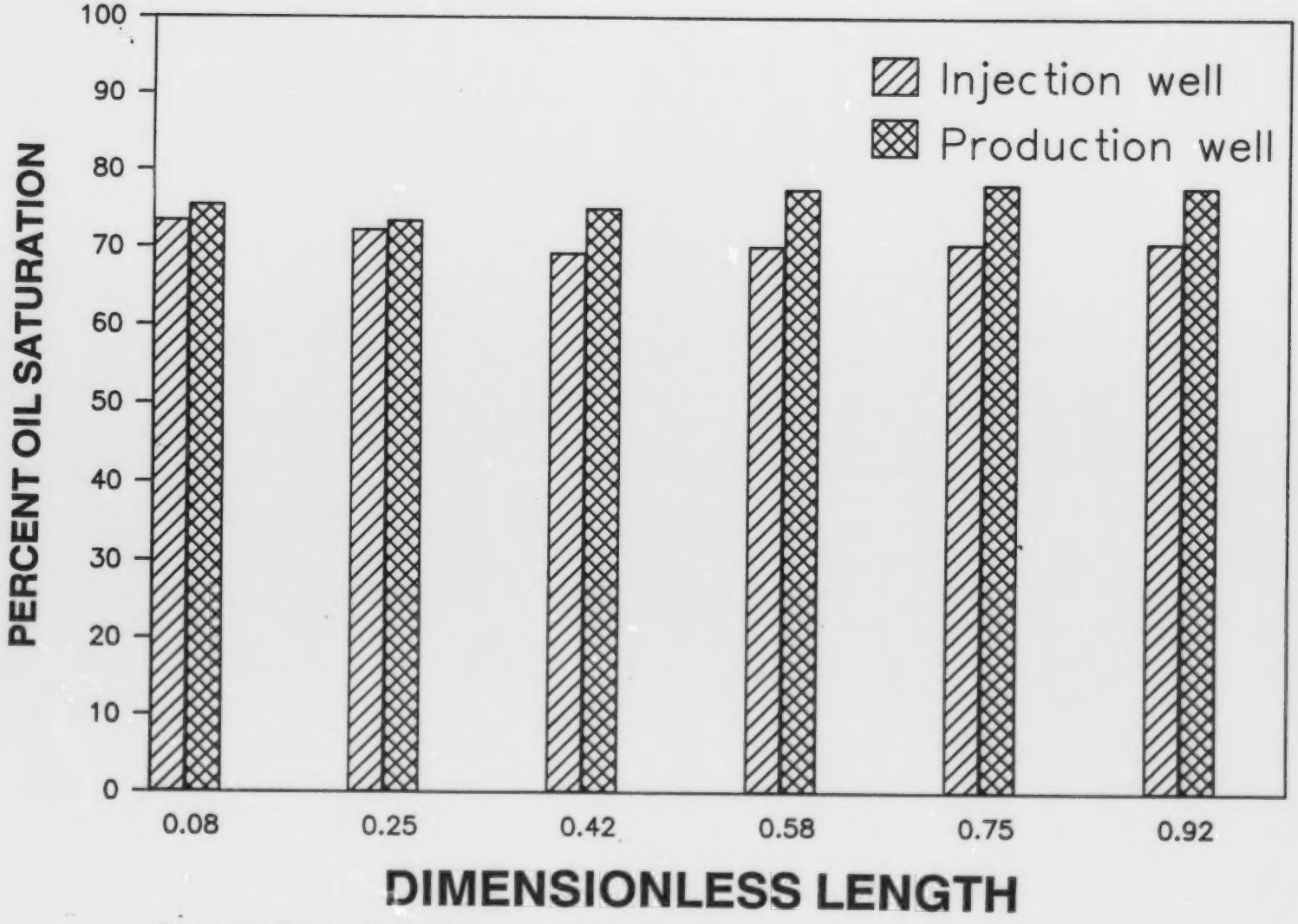

Figure 17. Final In Situ Oil Saturation of Run 9

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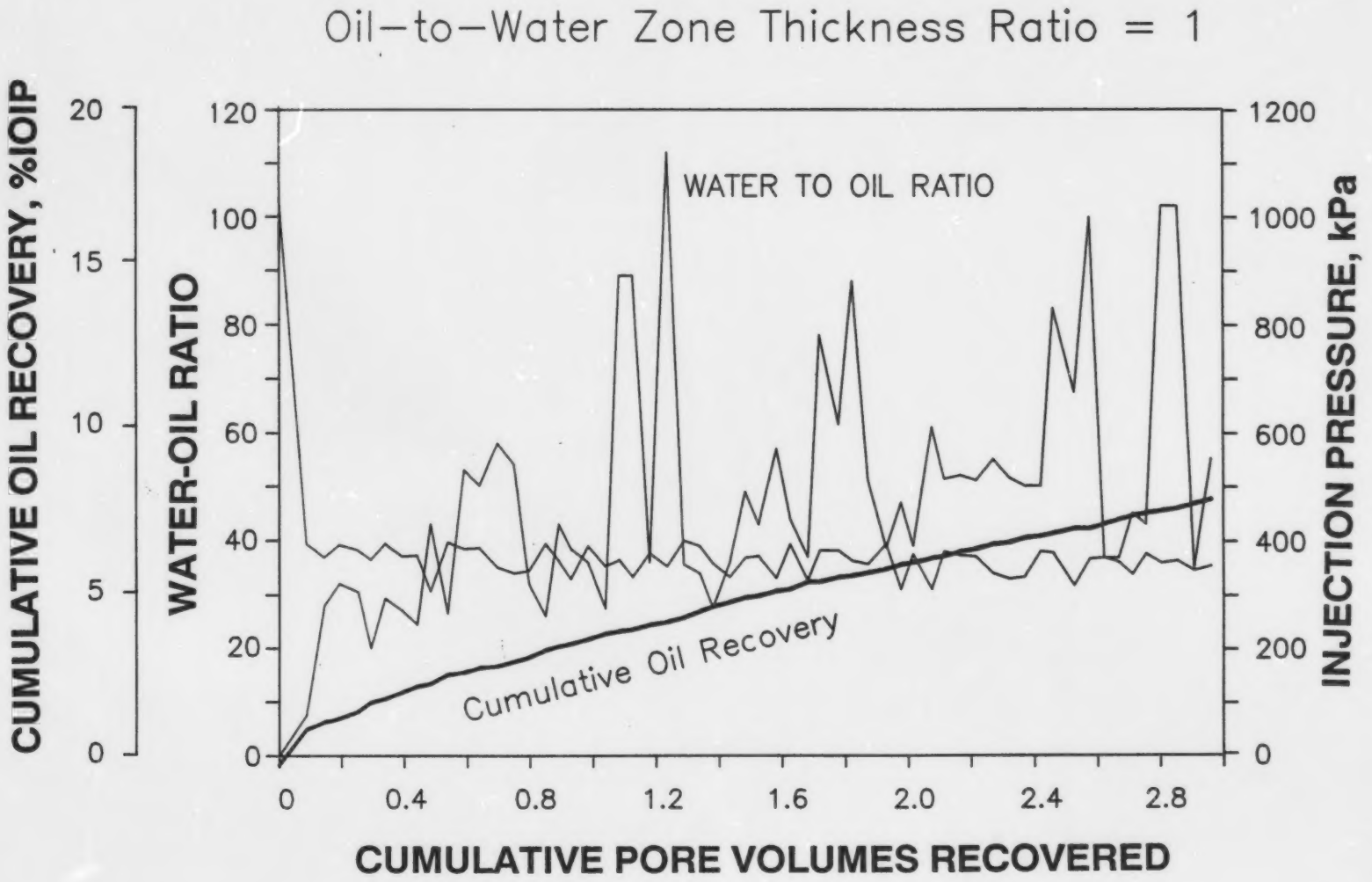

Figure 18. Recovery Performance of Run 10 ($h_o/h_b = 1$)

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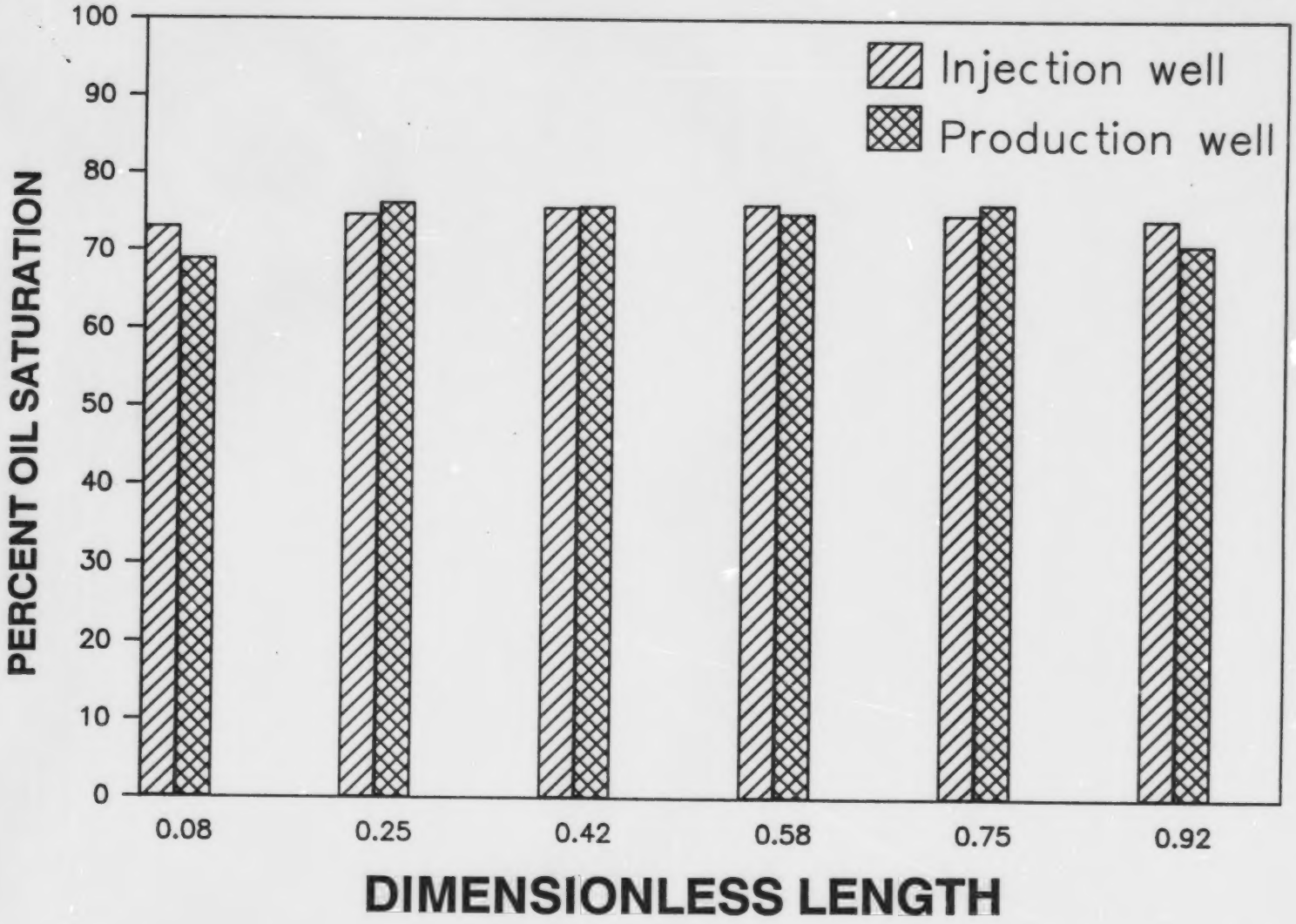

Figure 19. Final In Situ Oil Saturation of Run 10

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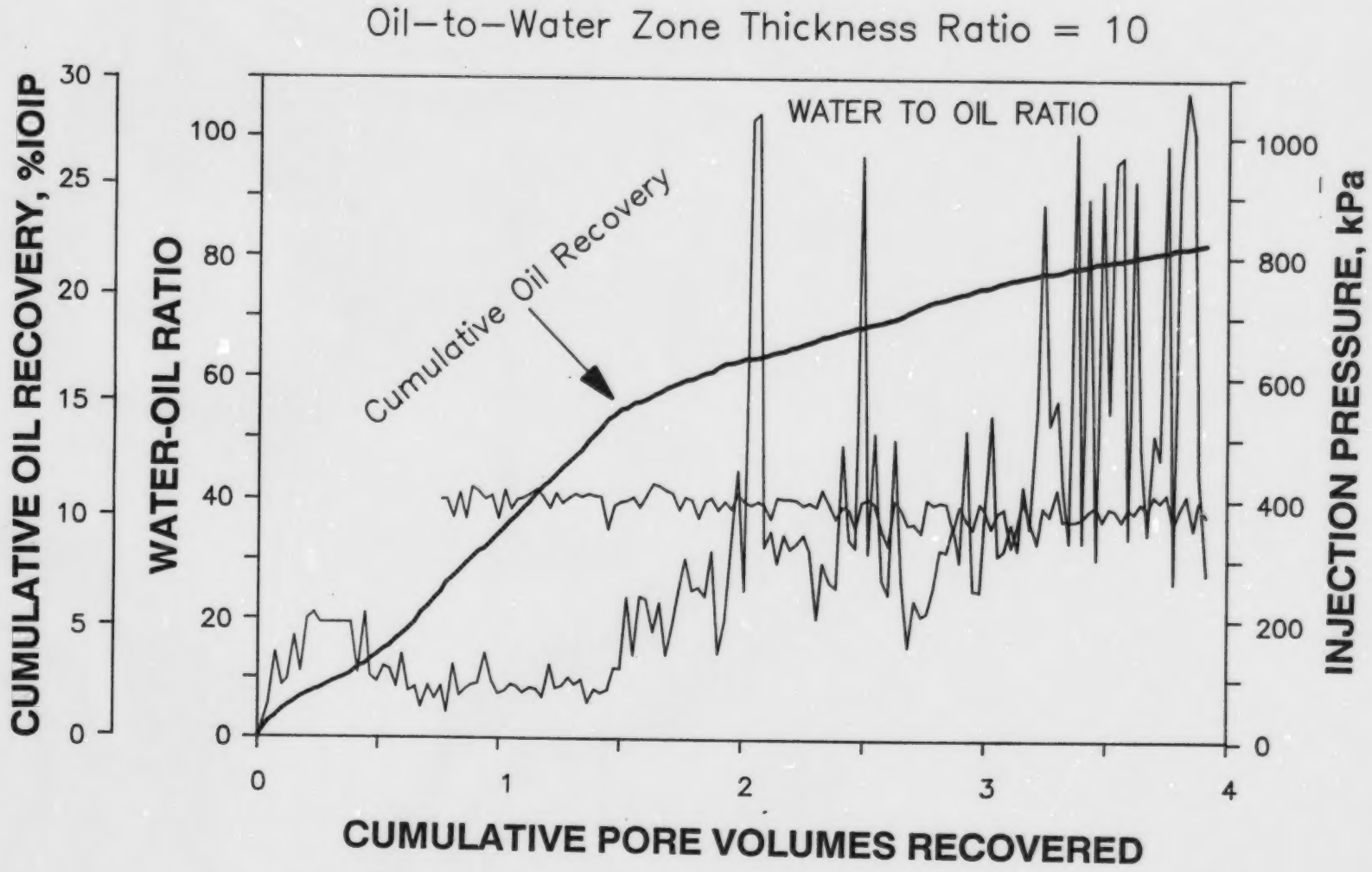

Figure 20. Recovery Performance of Run 11 ($h_o/h_b = 10$)

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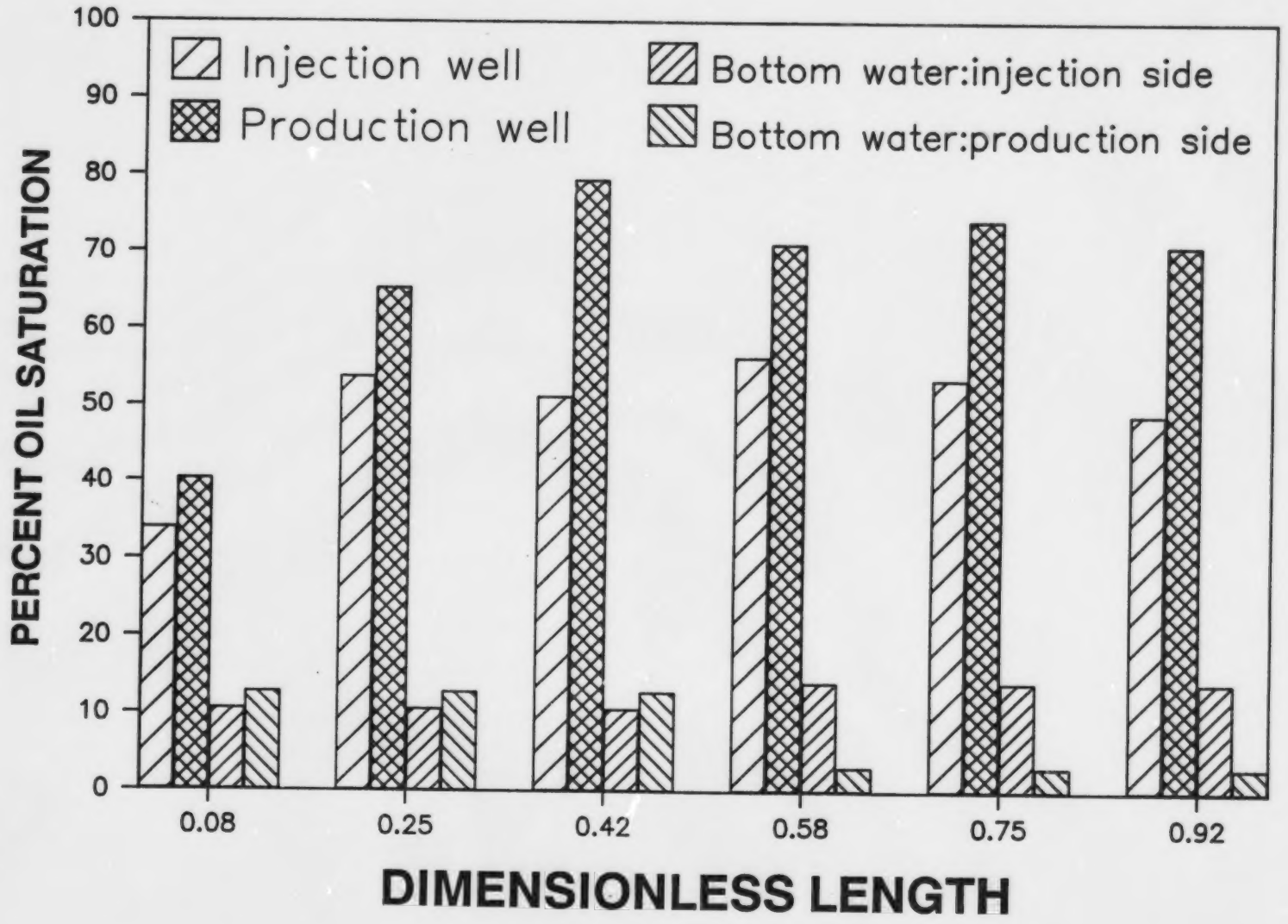

Figure 21. Final In Situ Oil Saturation of Run 11

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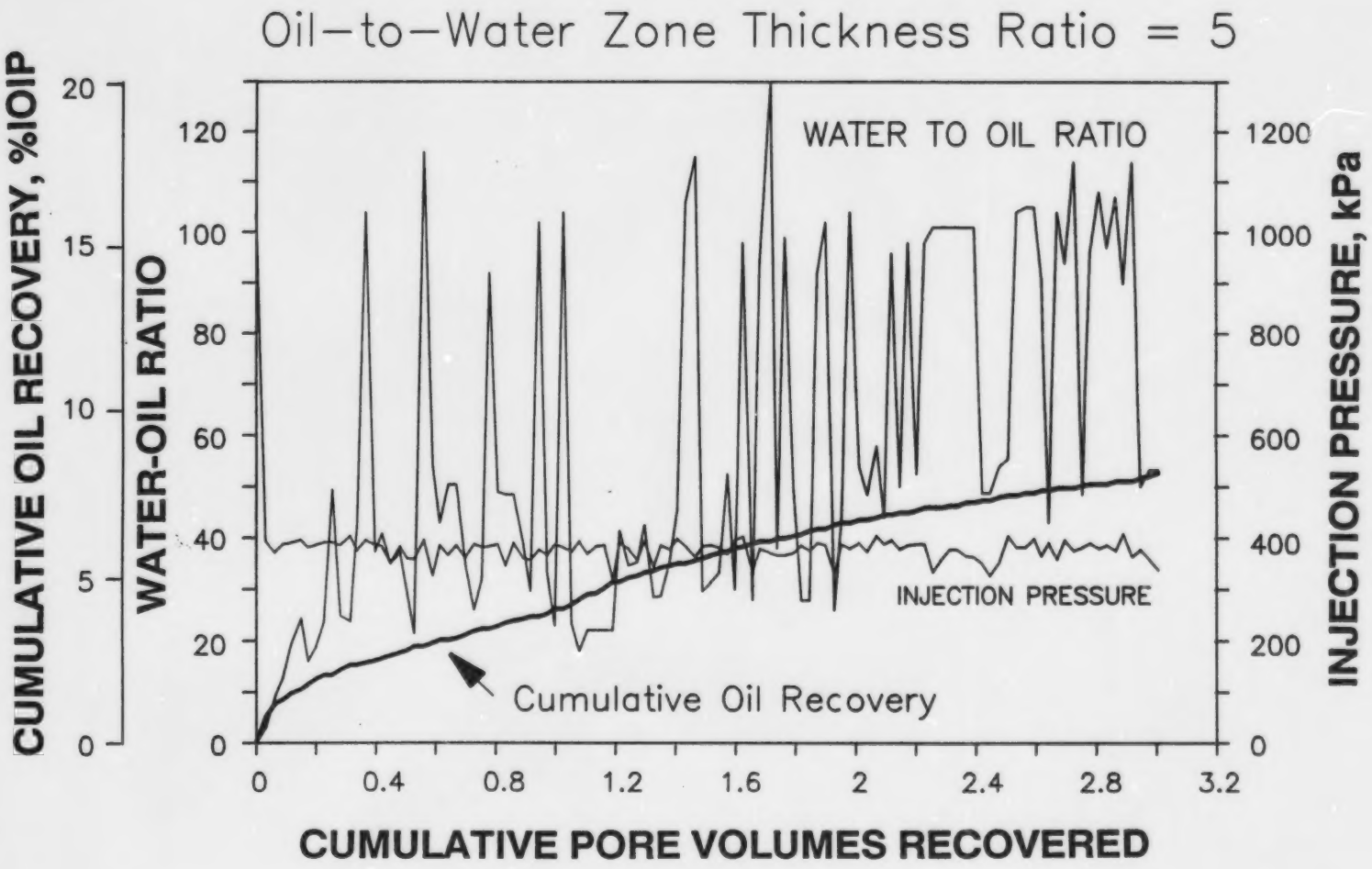

Figure 22. Recovery Performance of Run 12 ($h_o/h_b = 5$ with shale breaks)

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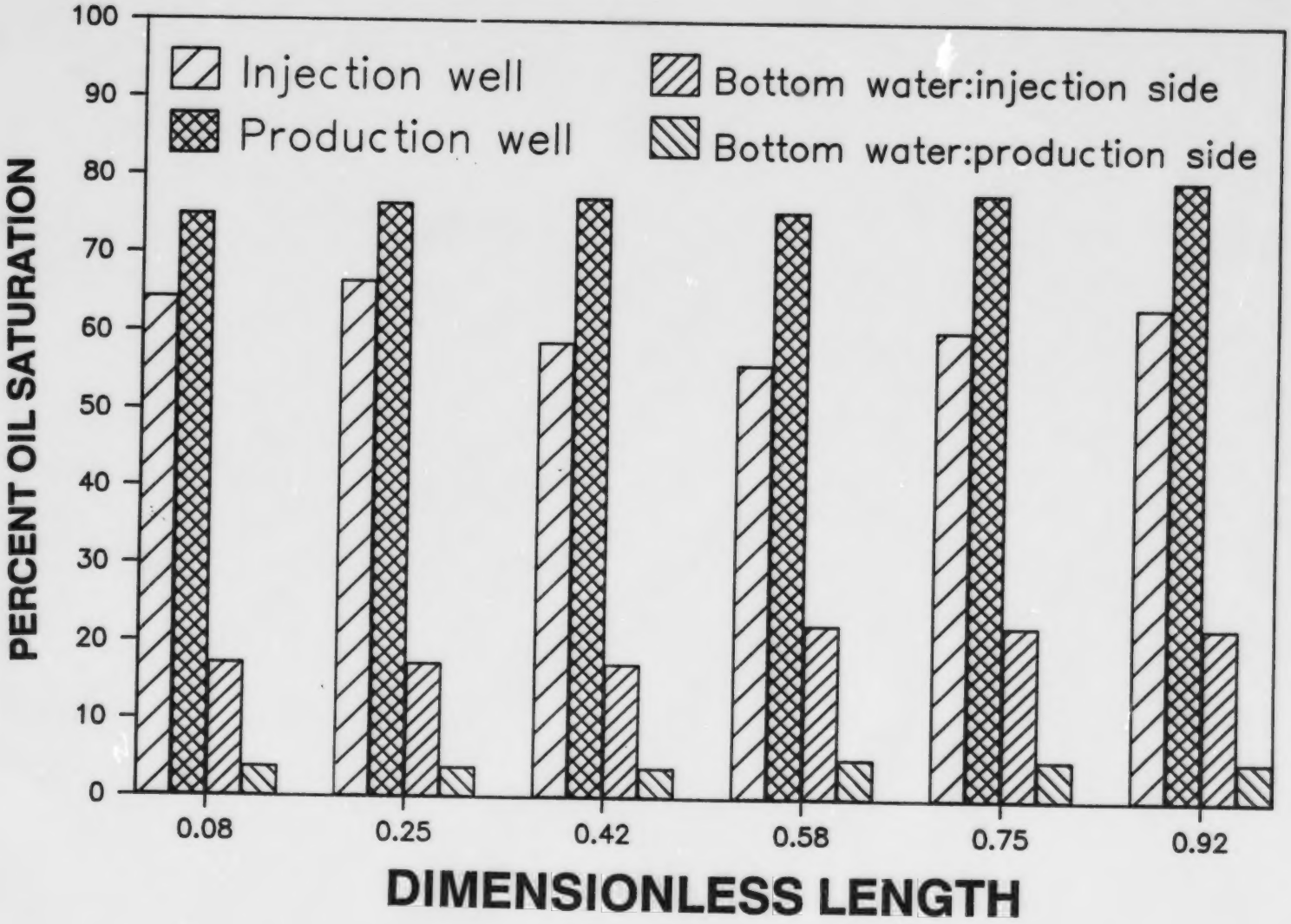

Figure 23. Final In Situ Oil Saturation of Run 12

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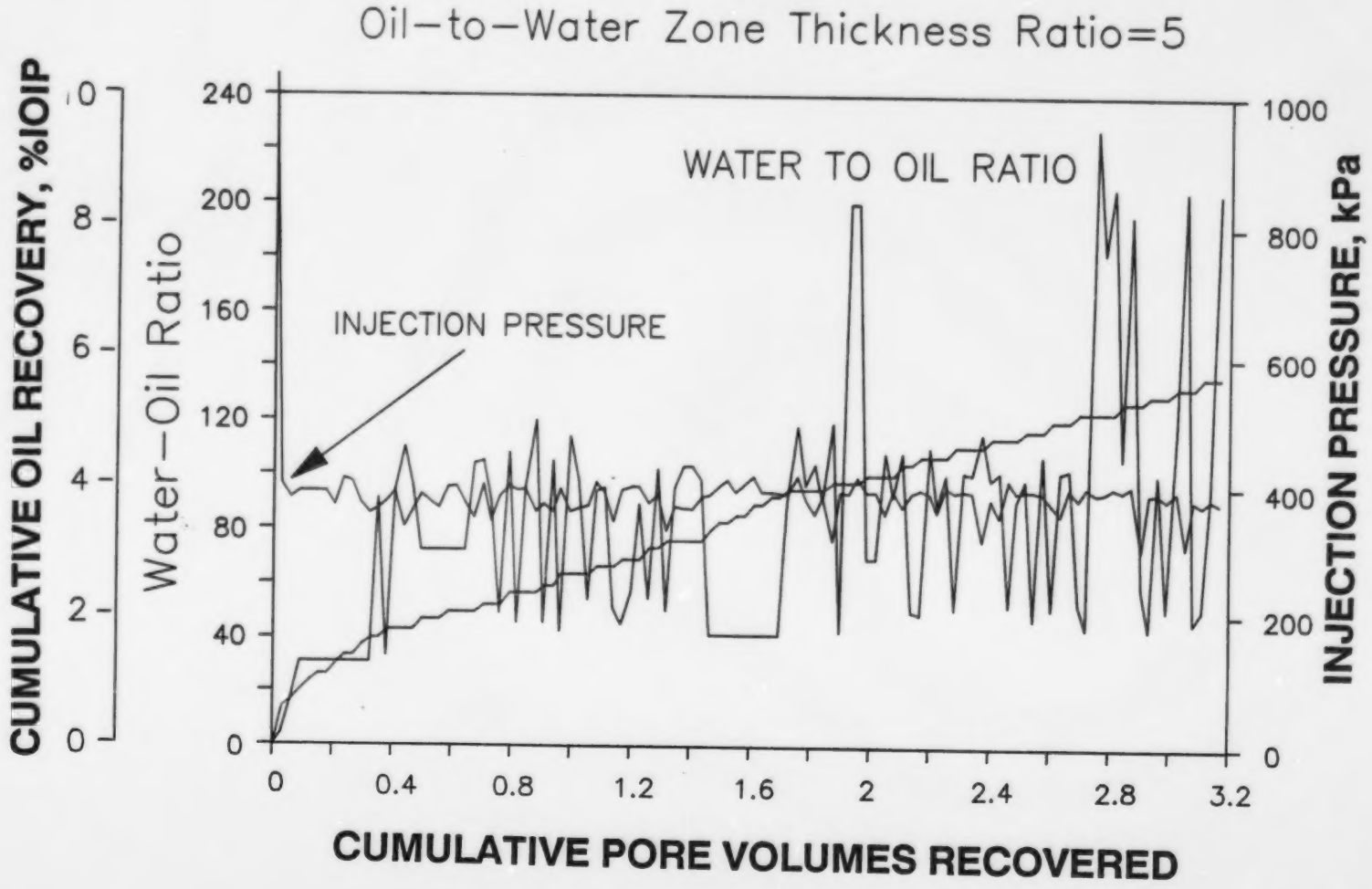

Figure 24. Recovery Performance of Run 13 (h_o/h_b=5 with vertical fractures)

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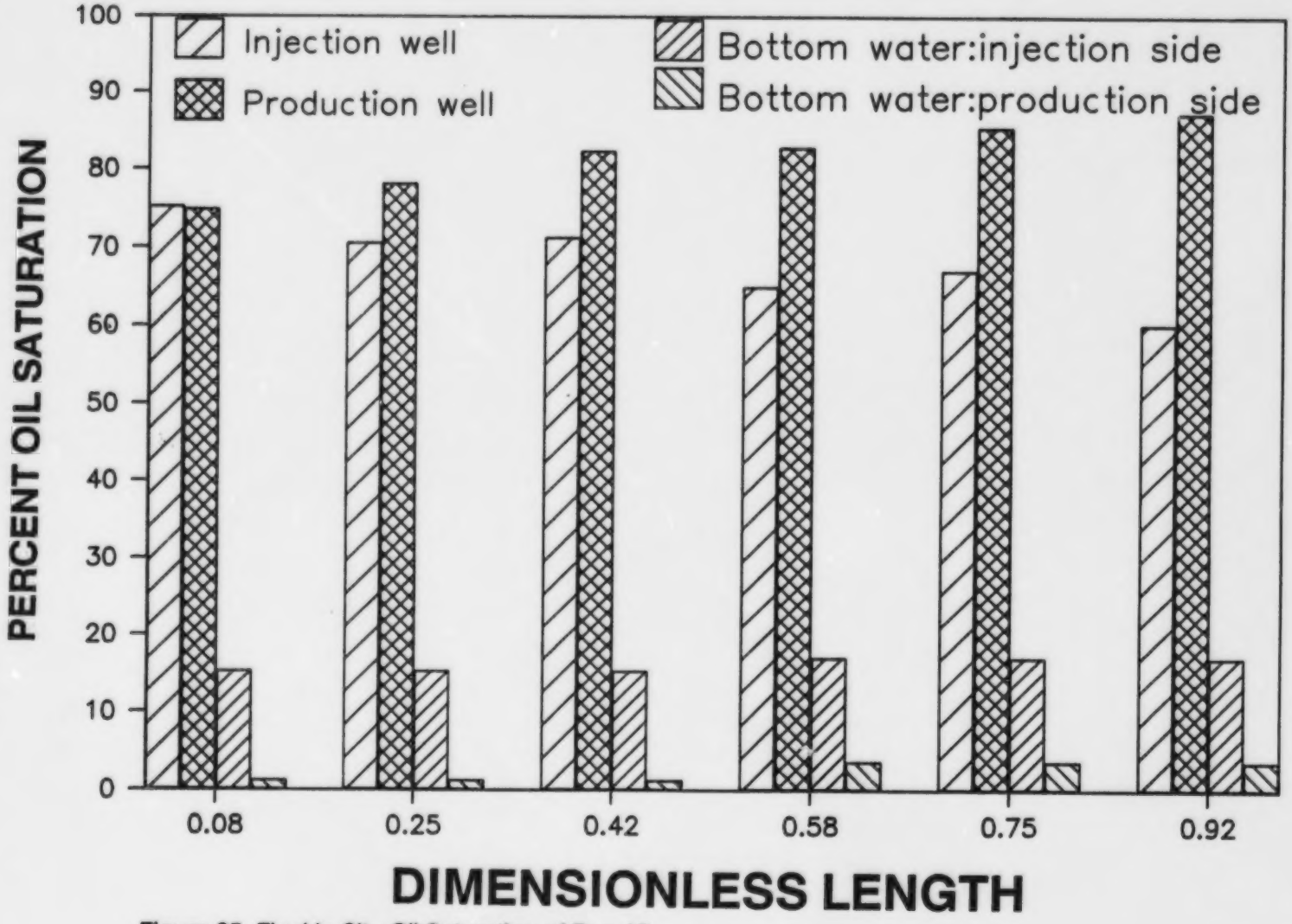

Figure 25. Final In Situ Oil Saturation of Run 13

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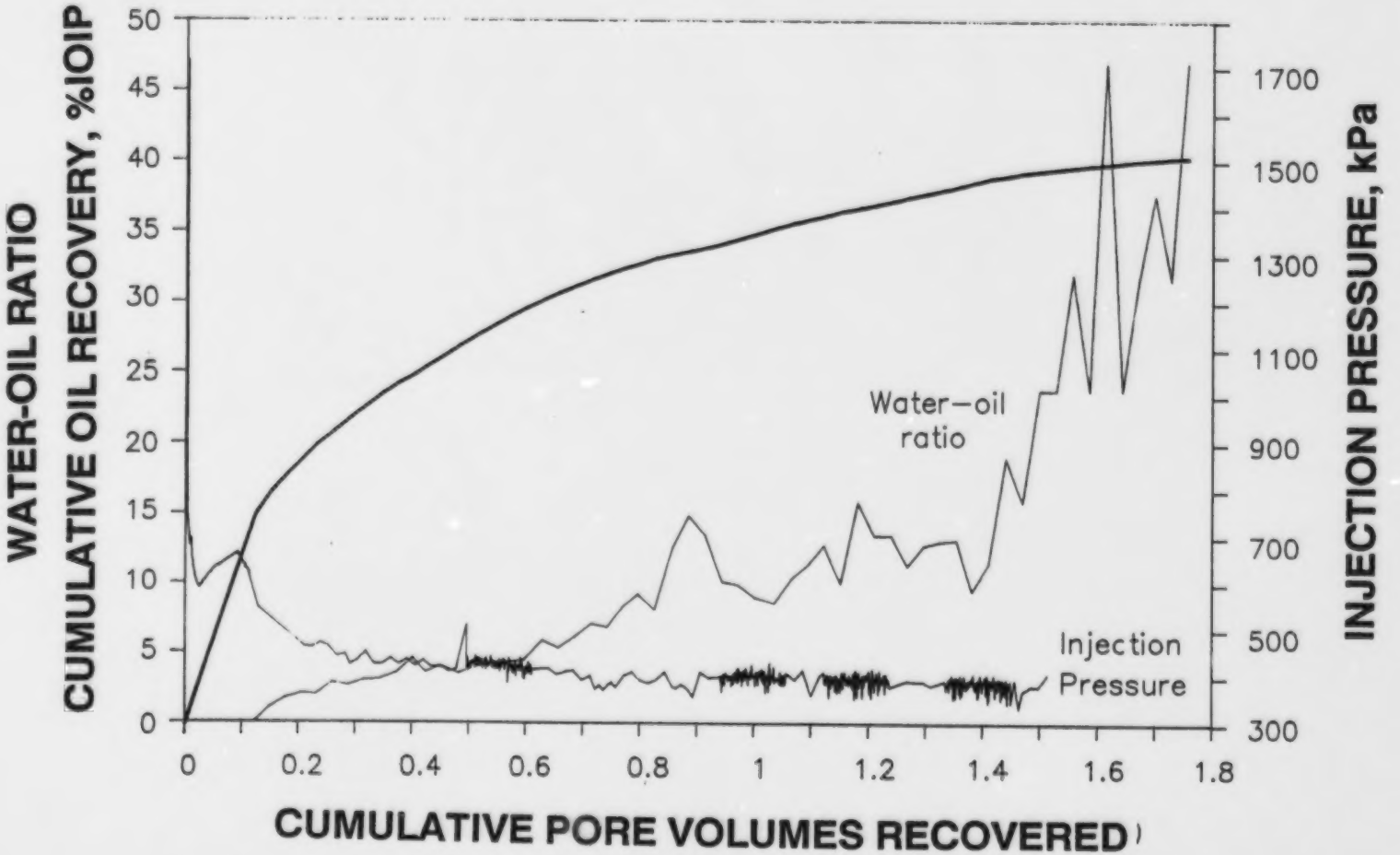

Figure 26. Recovery Performance of Run 14 (vertical injector and horizontal producer)

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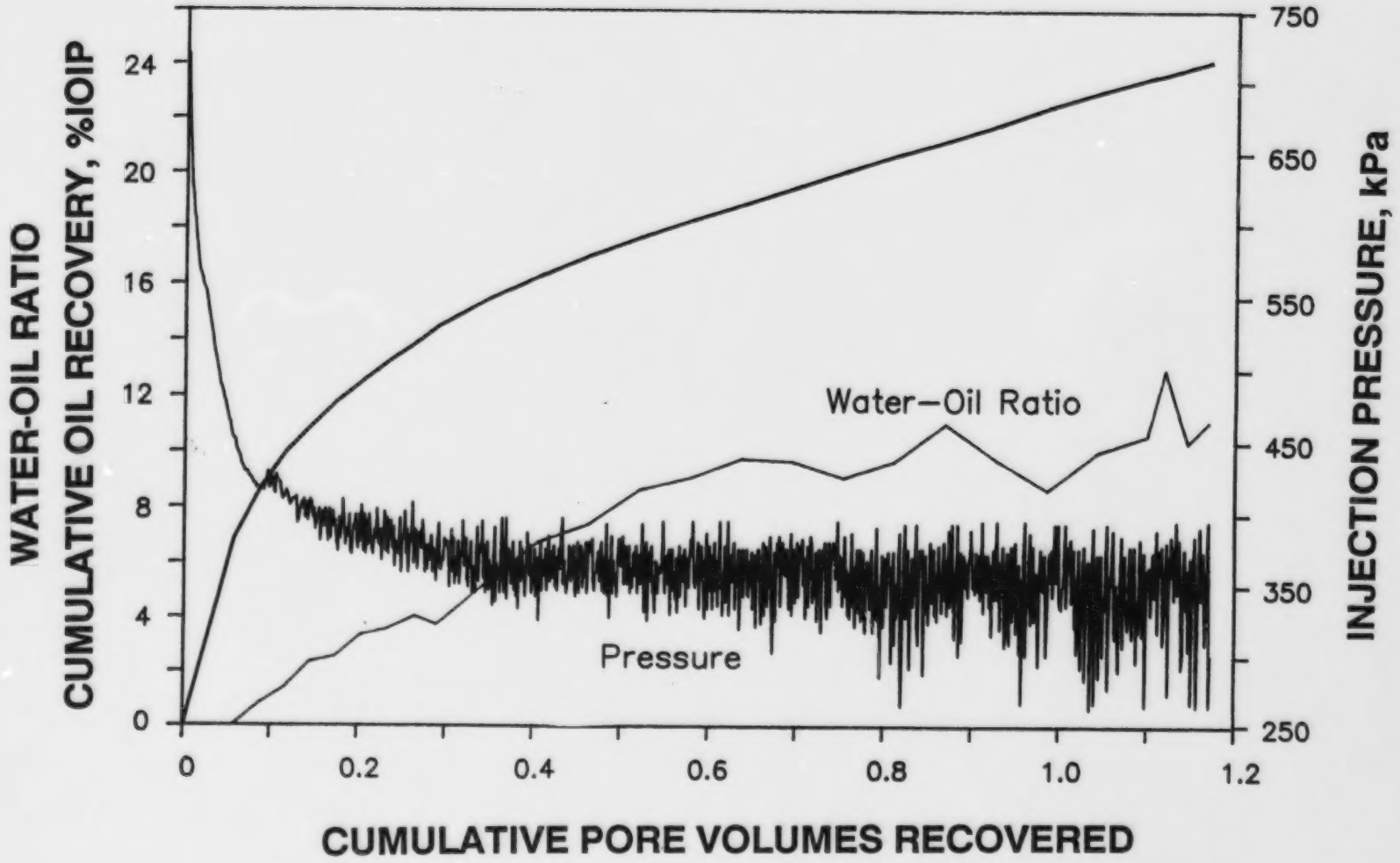

Figure 27. Recovery Performance of Run 15 (vertical injector and vertical producer)

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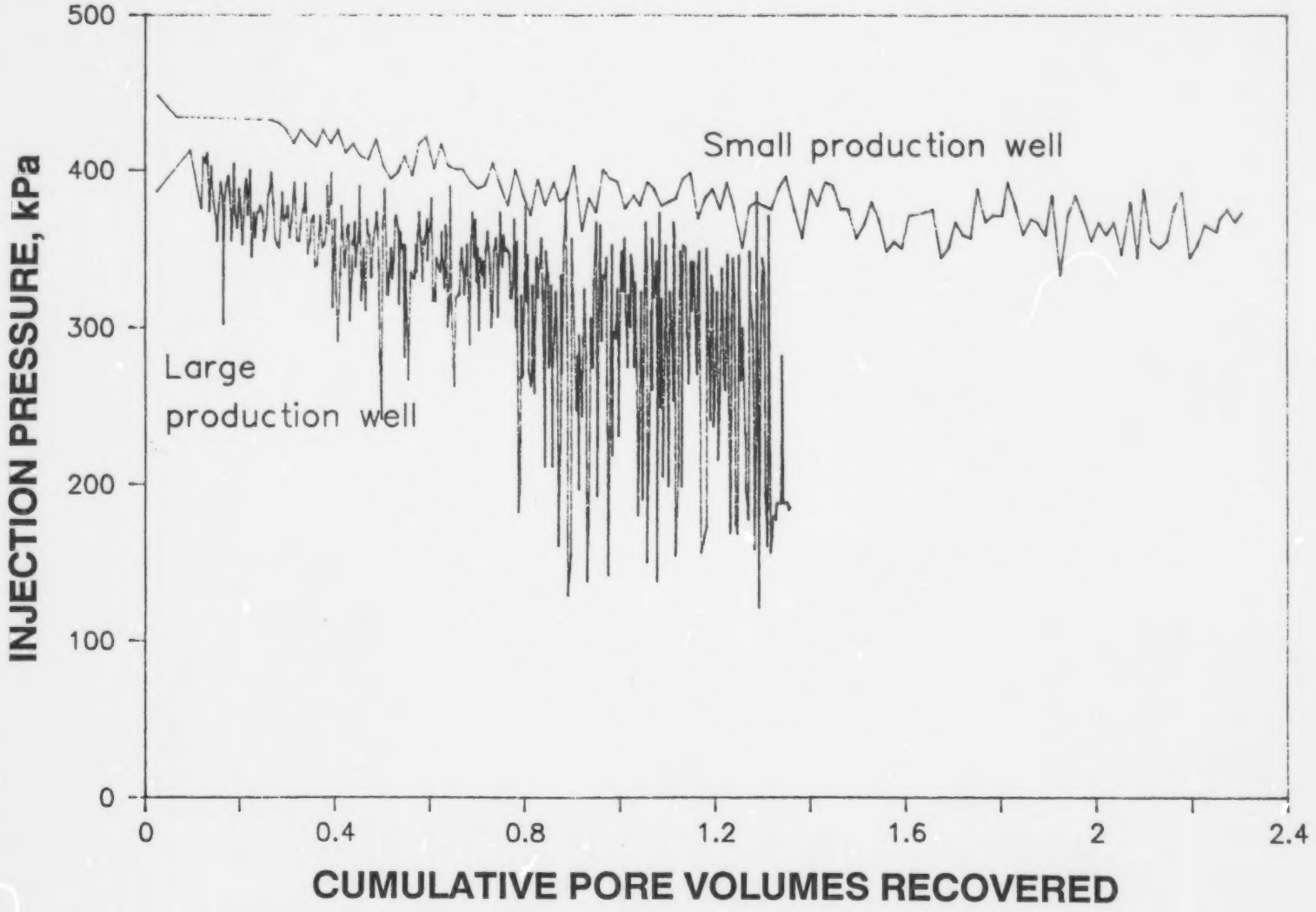

Figure 28. Comparison of Injection Pressures for Runs 1 and 2 (large and small well diameters)

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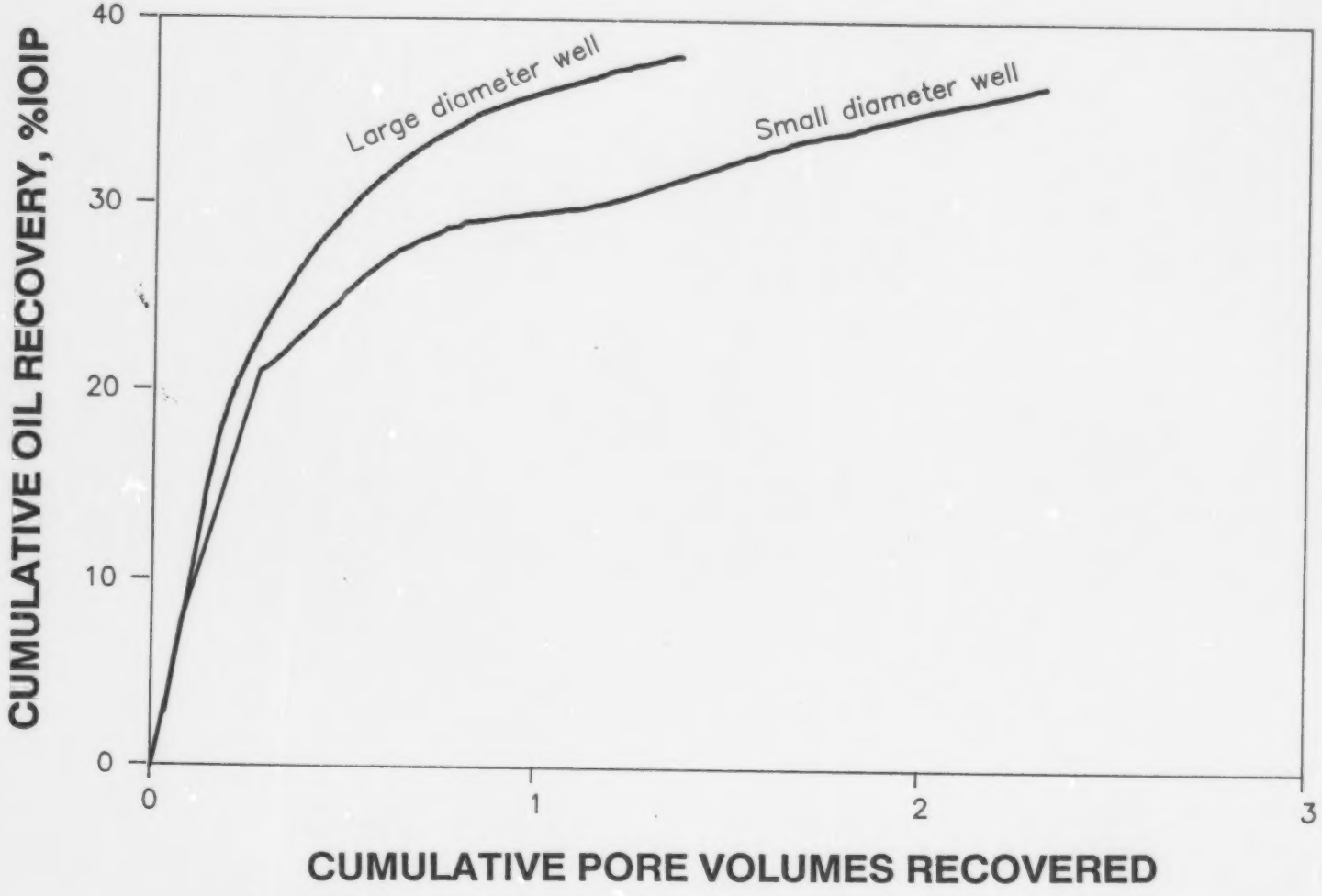

Figure 29. Comparison of Oil Recoveries for Different Production Well Diameters

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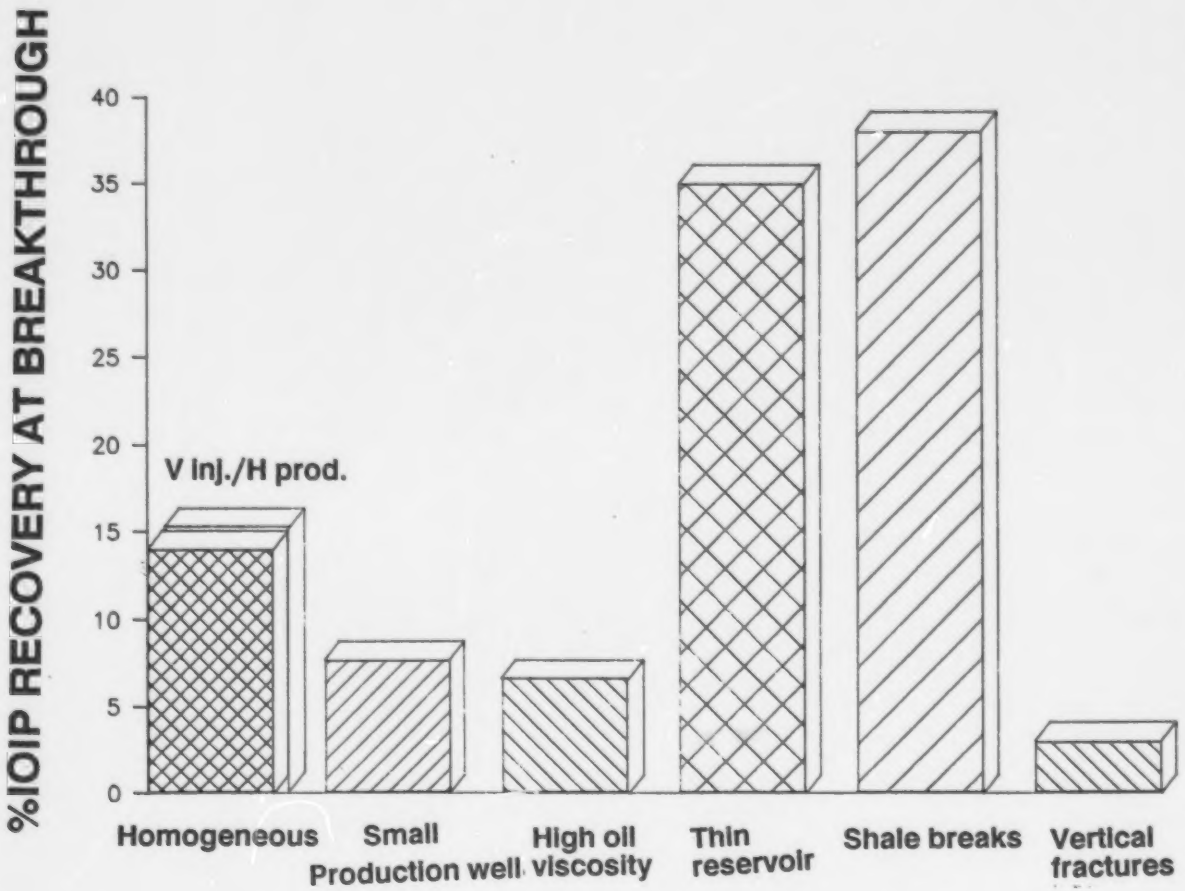

Figure 30. Comparison of Water Breakthrough Times For Different Runs

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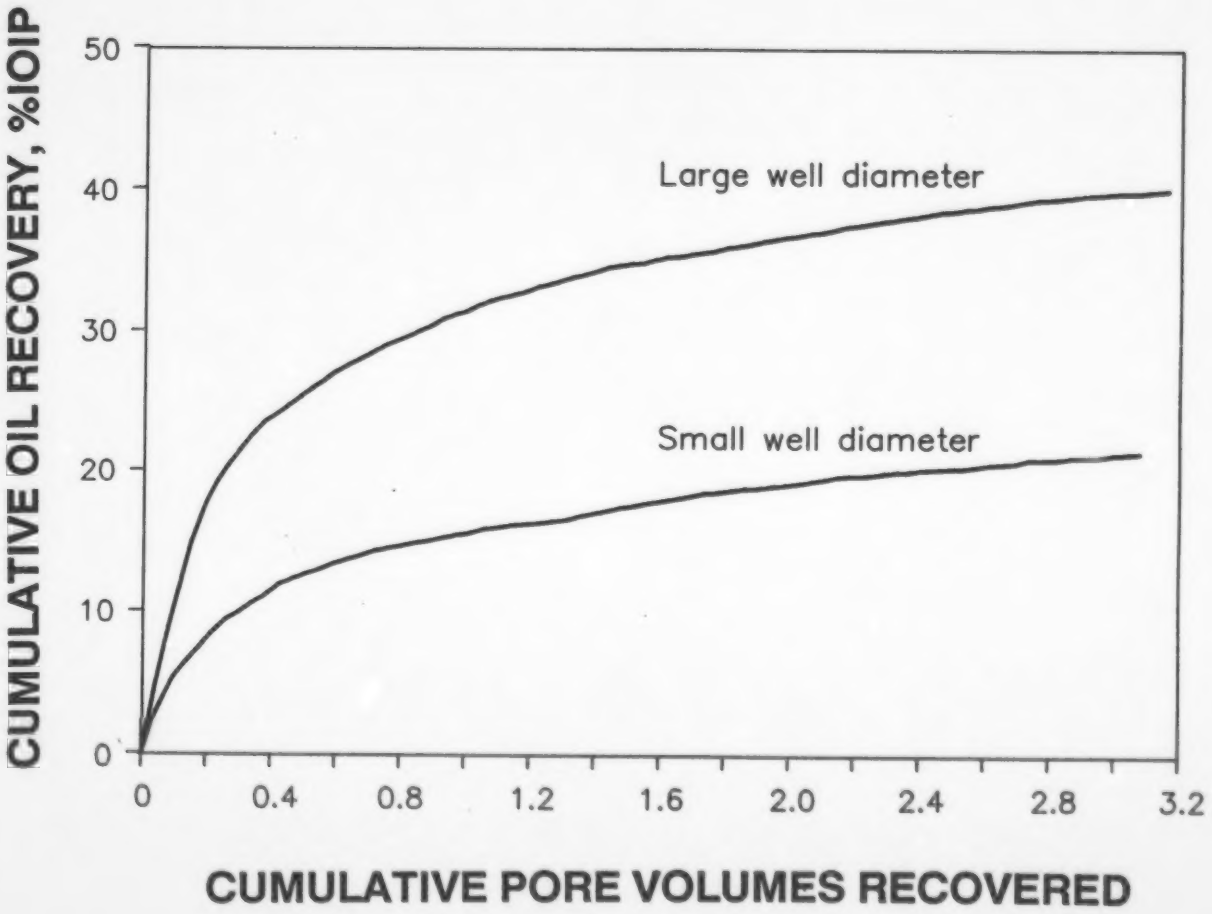

Figure 31. Effect of Injection Well Diameters on Oil Recovery

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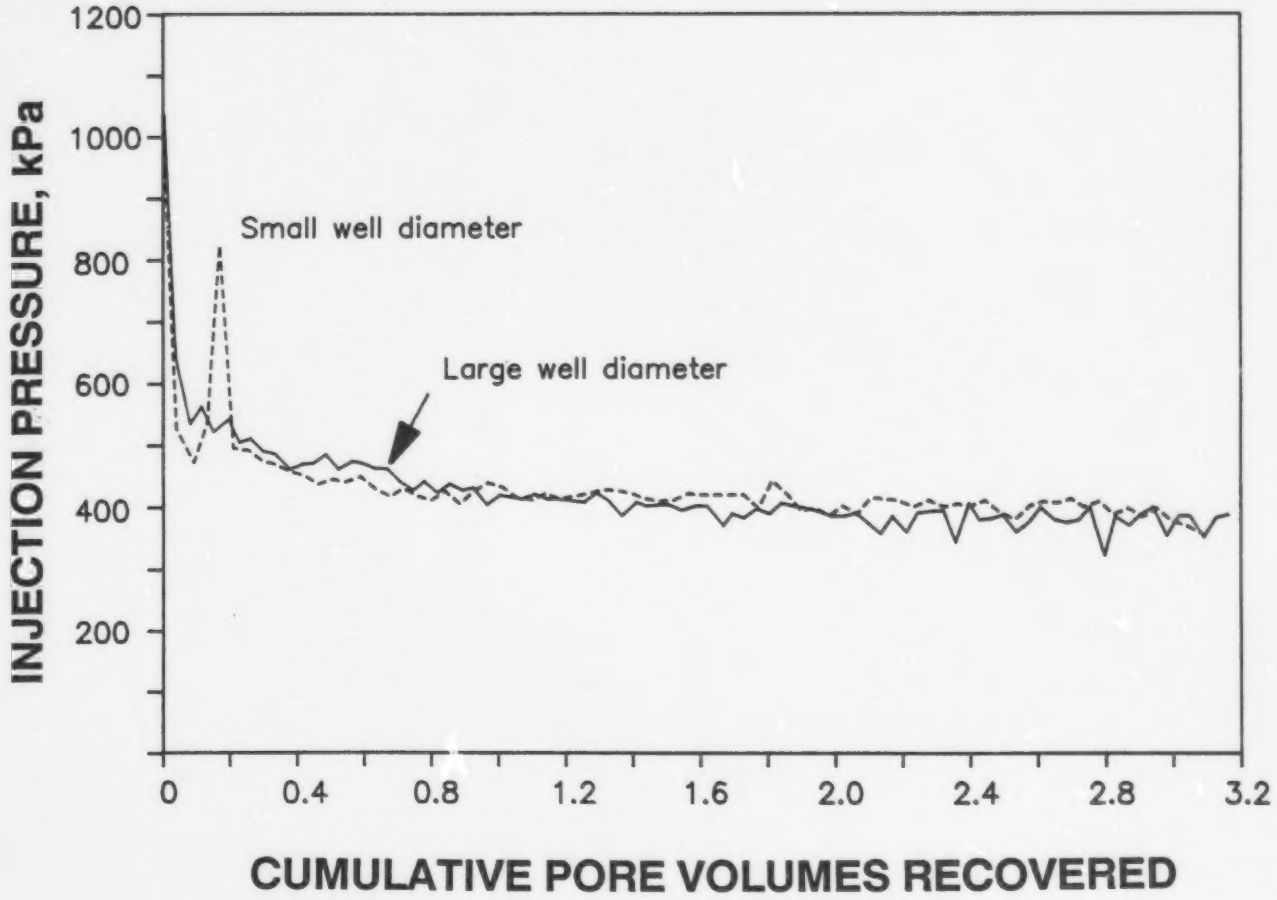

Figure 32. Effect of Injection Well Diameters on Injection Pressures

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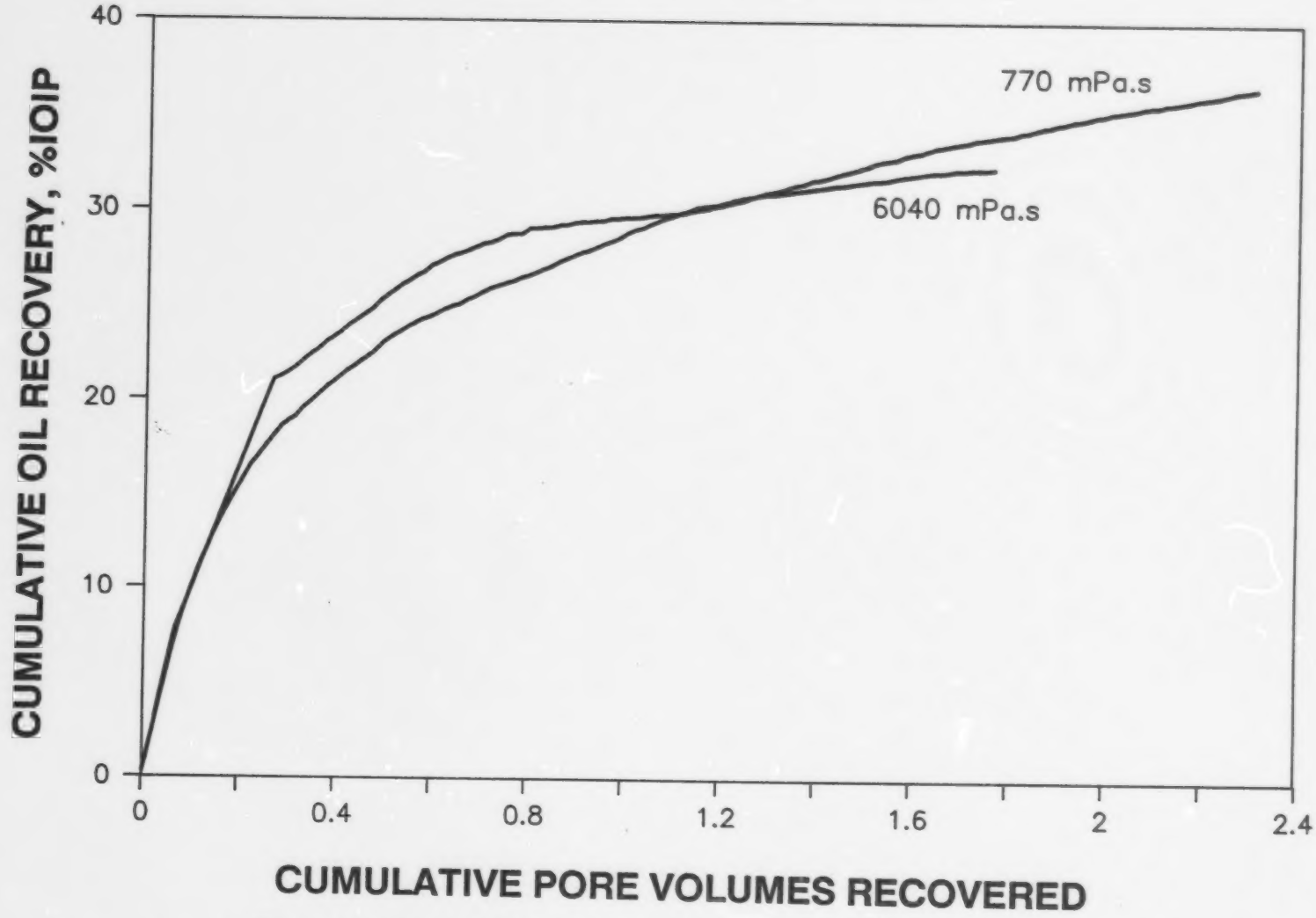

Figure 33. Effect of Oil Viscosity on Oil Recovery

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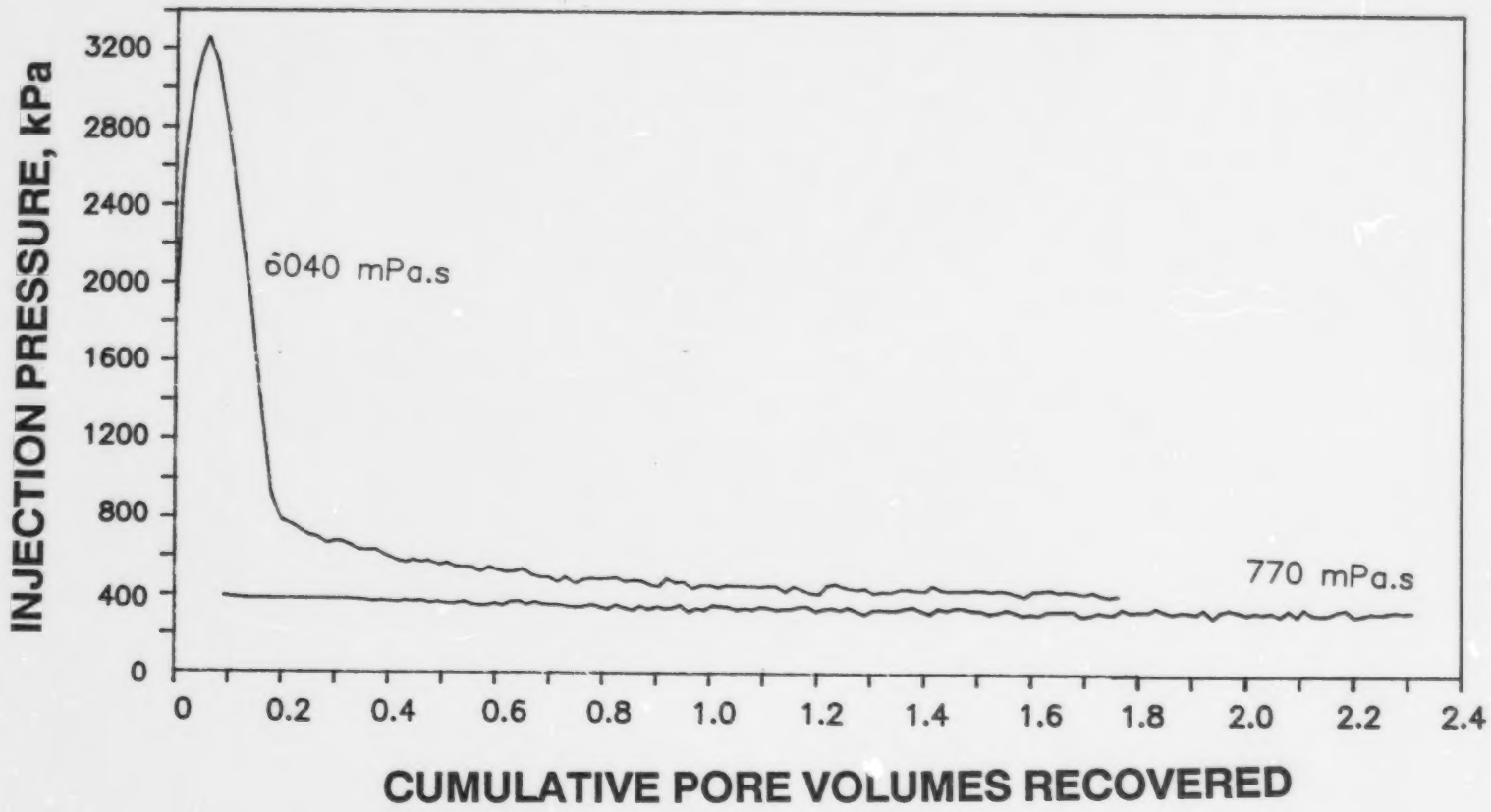

Figure 34. Effect of Oil Viscosity on Injection Pressures

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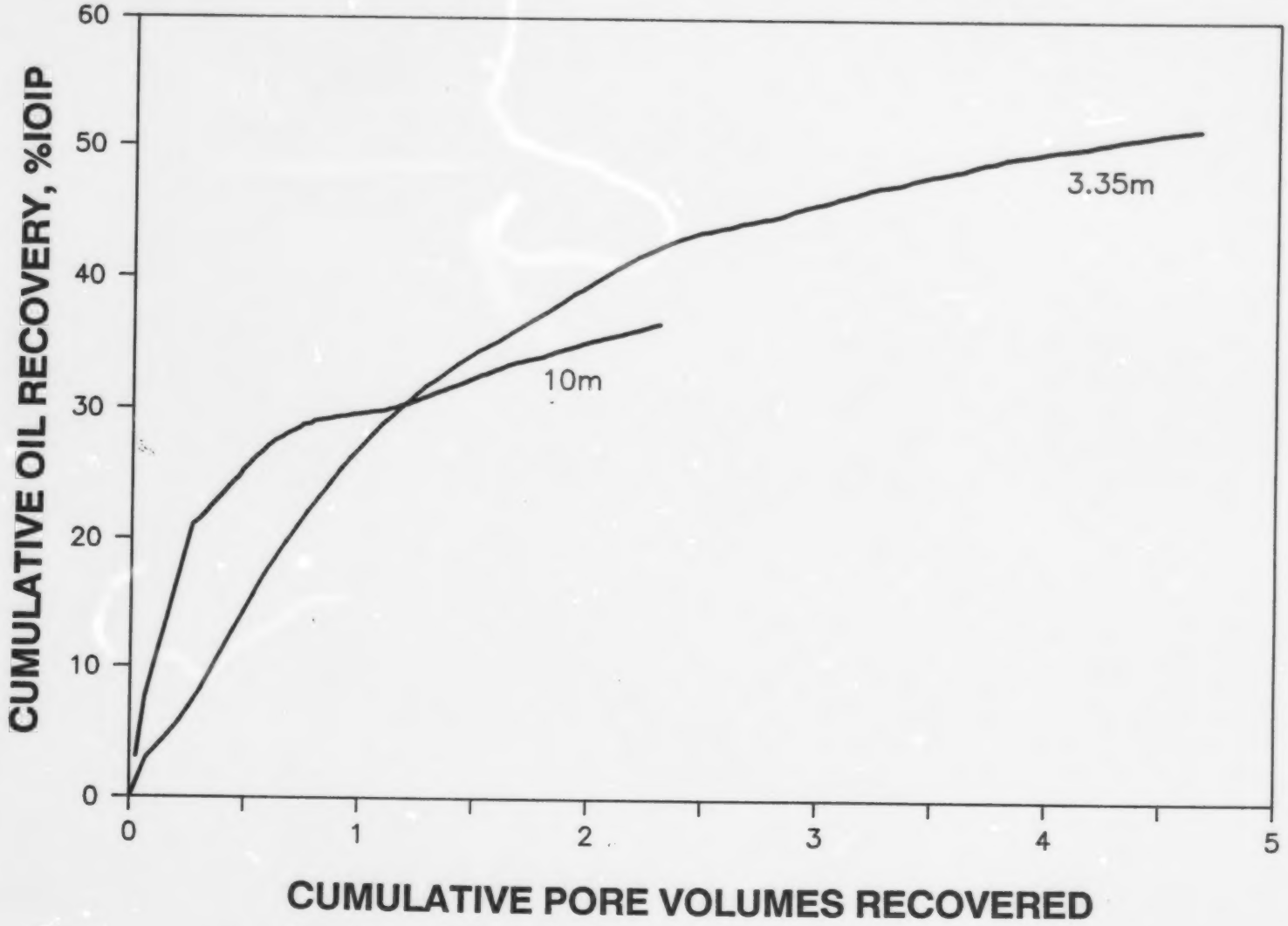

Figure 35. Effect of Reservoir Thickness on Oil Recovery

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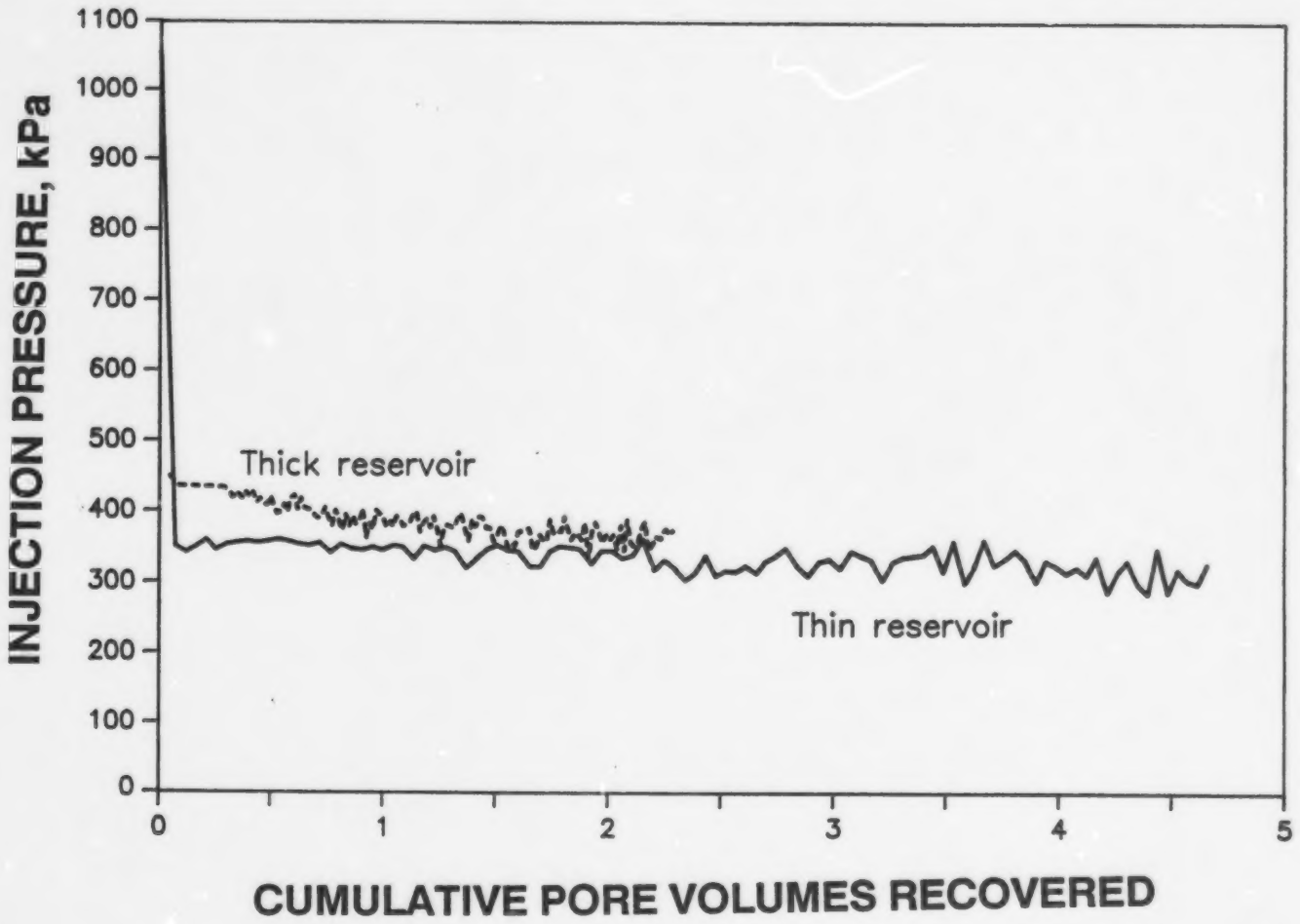

Figure 36. Effect of Reservoir Thickness on Injection Pressures

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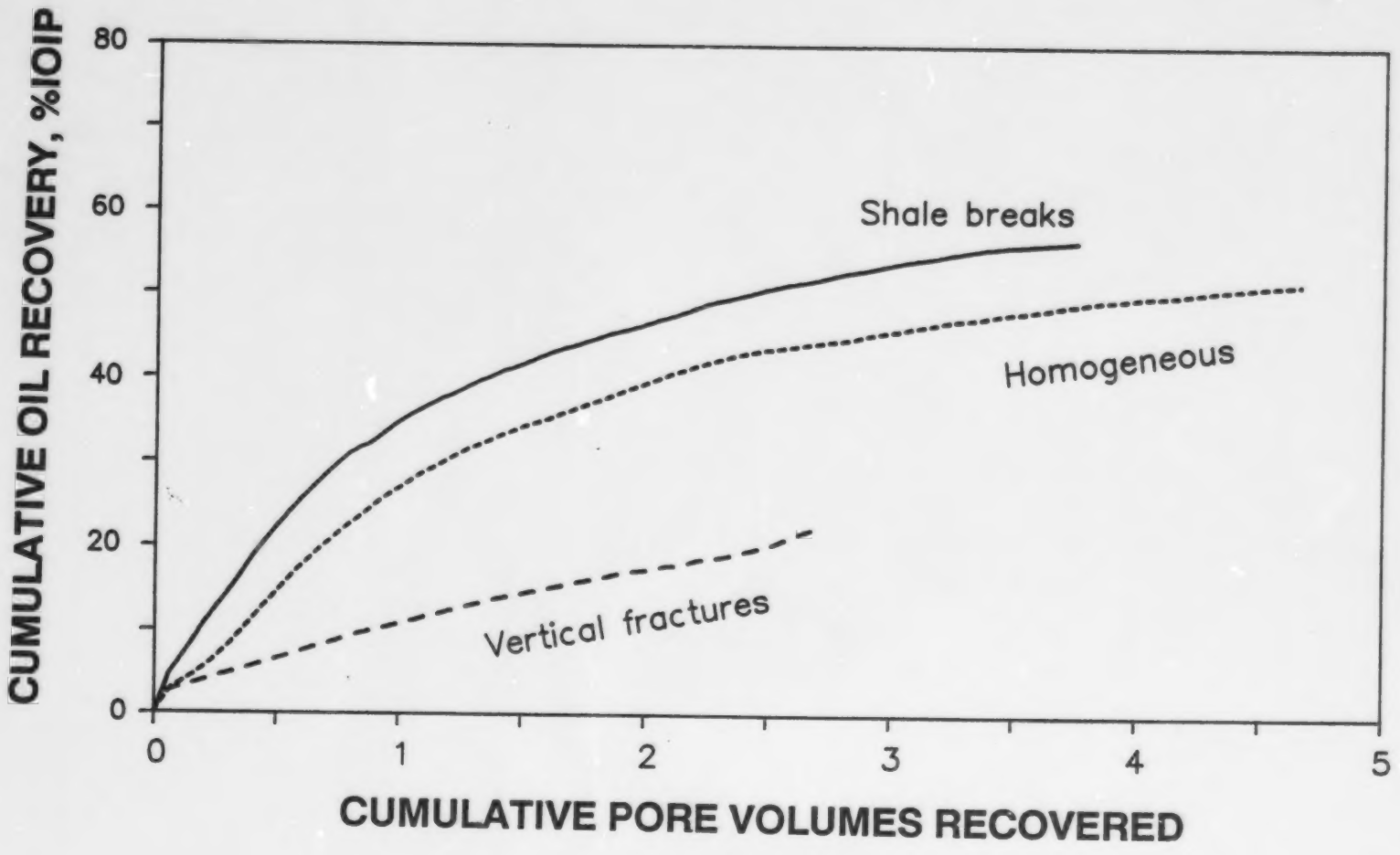

Figure 37. Effect of Reservoir Heterogeneity on Oil Recovery

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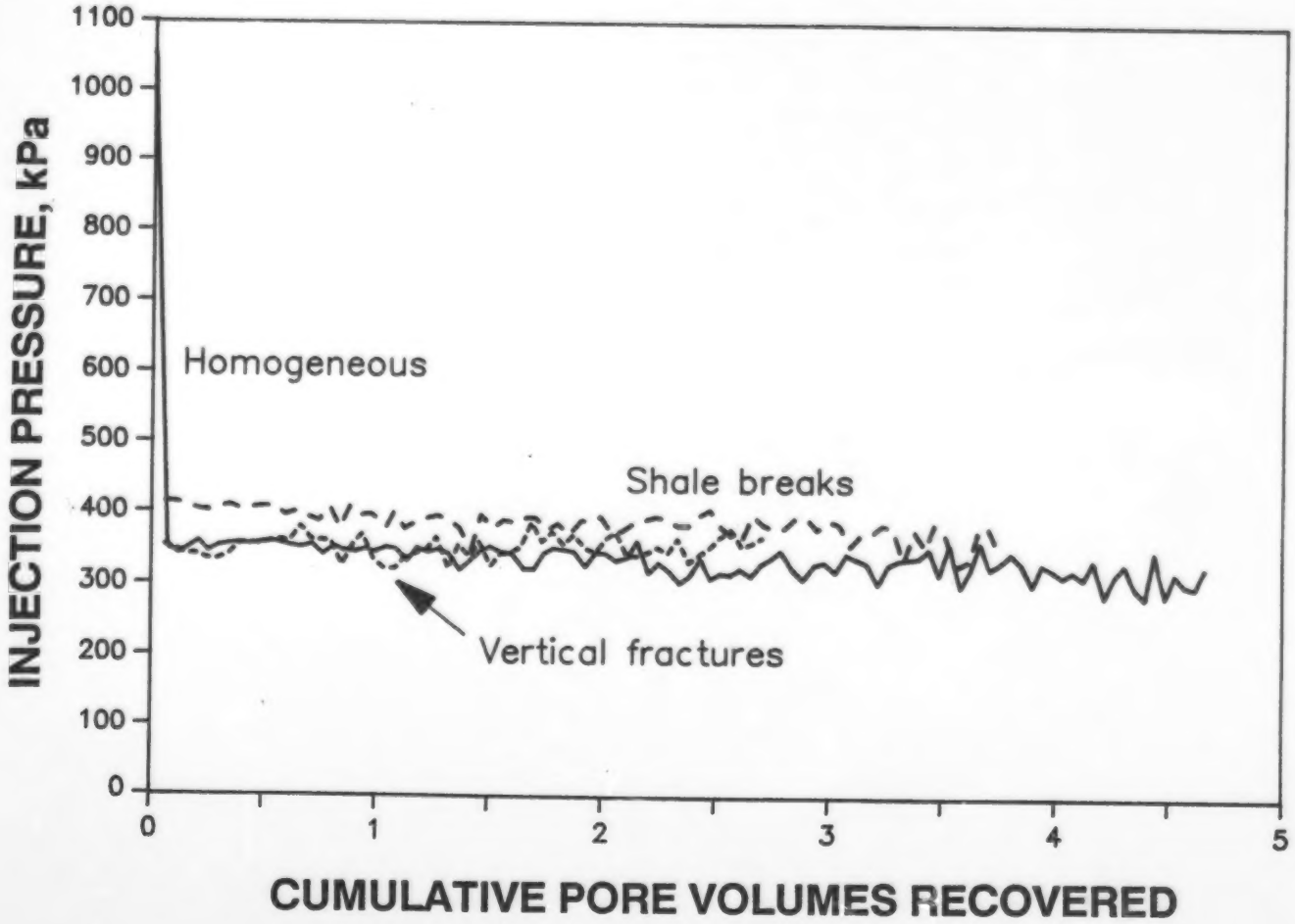

Figure 38. Effect of Reservoir Heterogeneity on Injection Pressures

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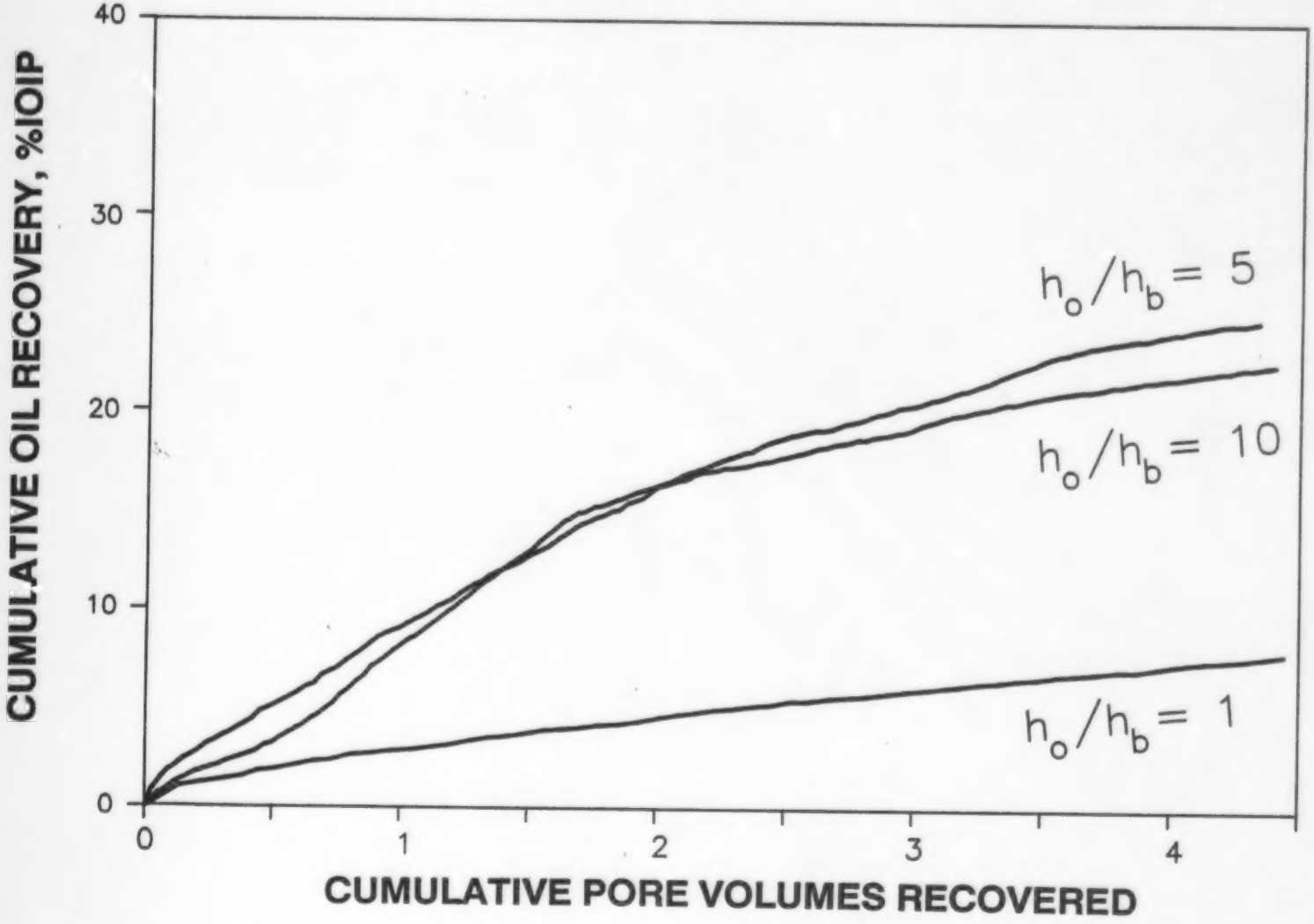

Figure 39. Effect of Oil-to-Water Zone Thickness Ratio on Oil Recovery

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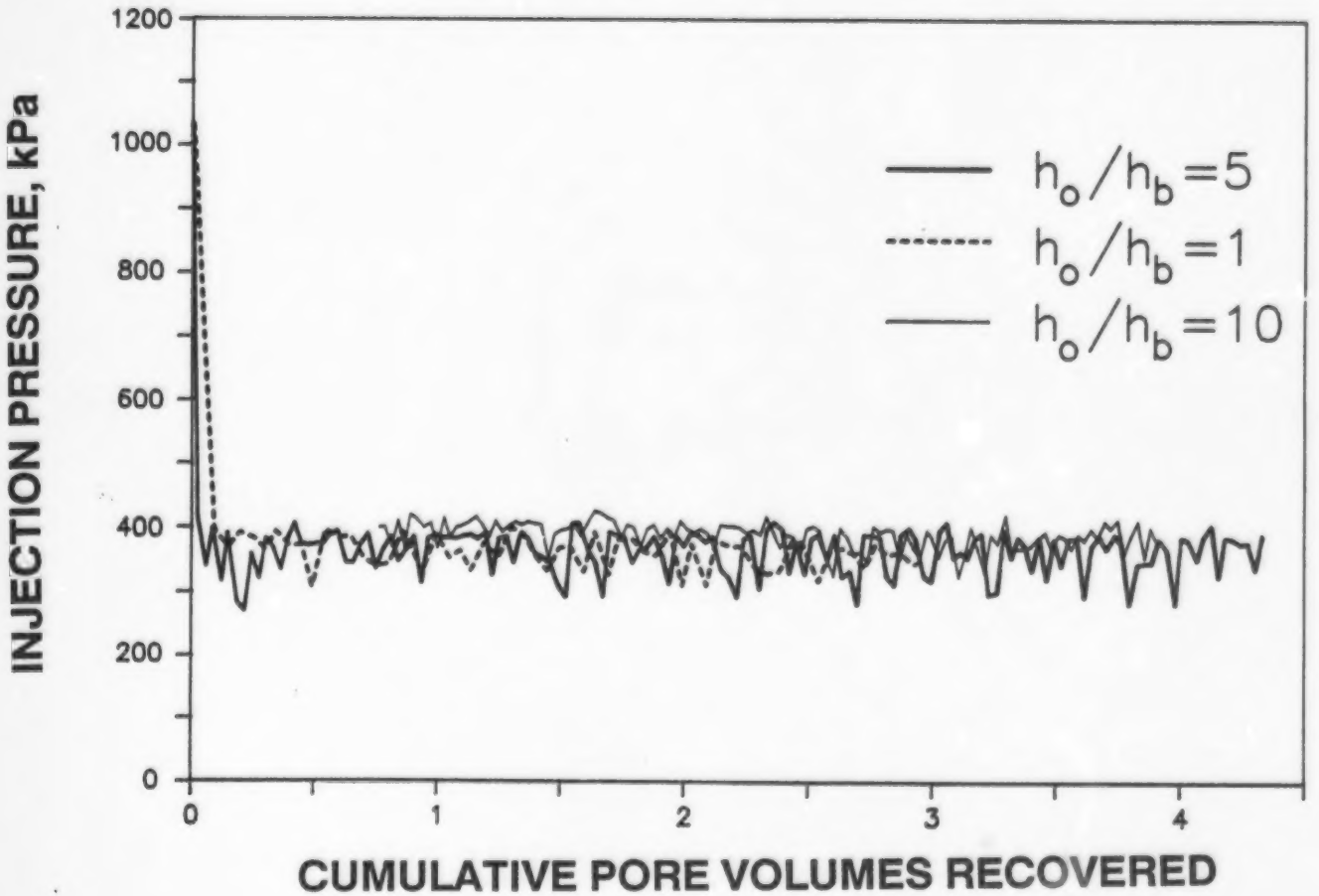

Figure 40. Effect of Oil-to-Water Zone Thickness Ratio on Injection Pressure

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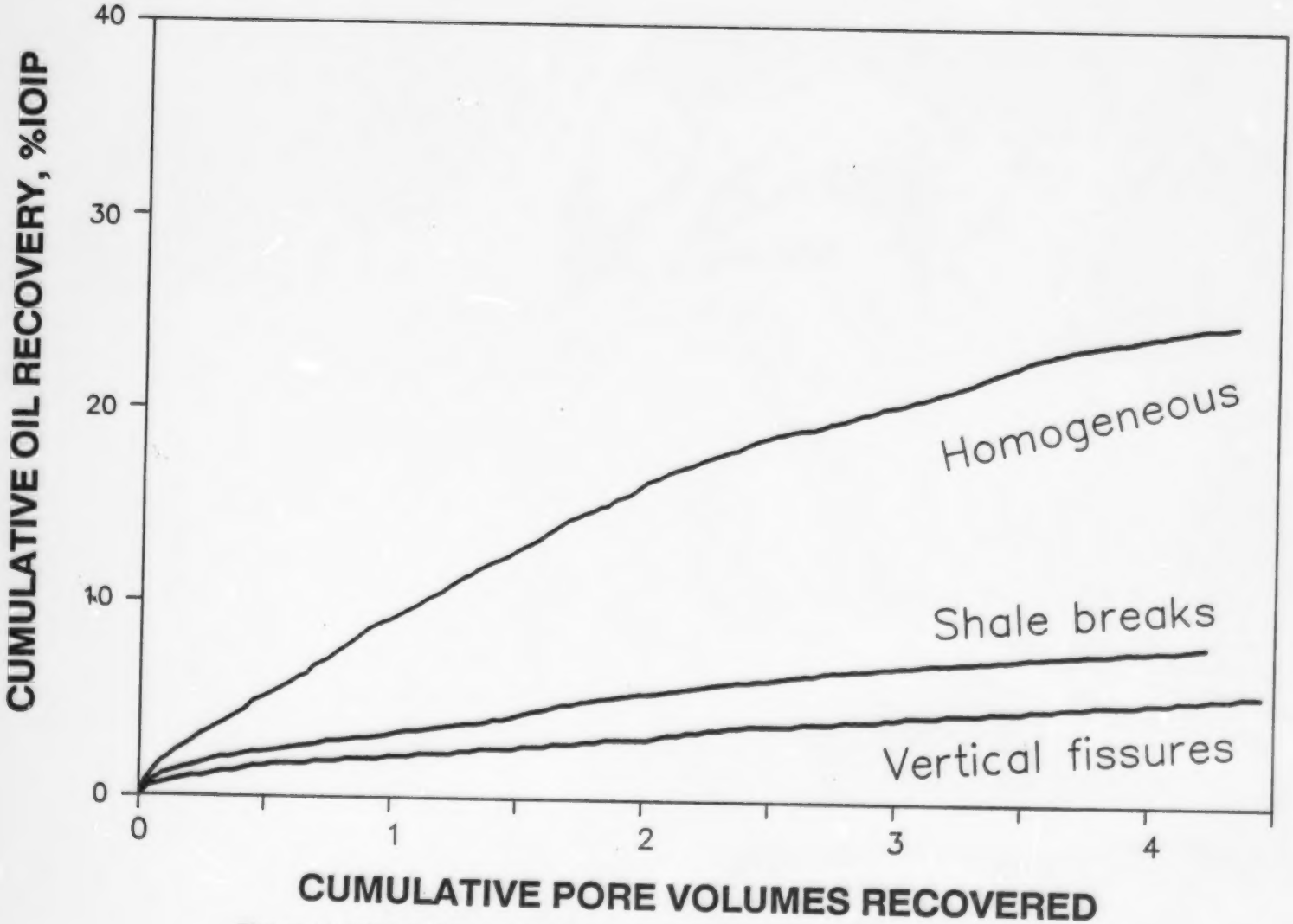

Figure 41. Effect of Reservoir Heterogeneity on Oil Recovery for Bottom-Water Reservoirs ($h_o/h_b=5$)

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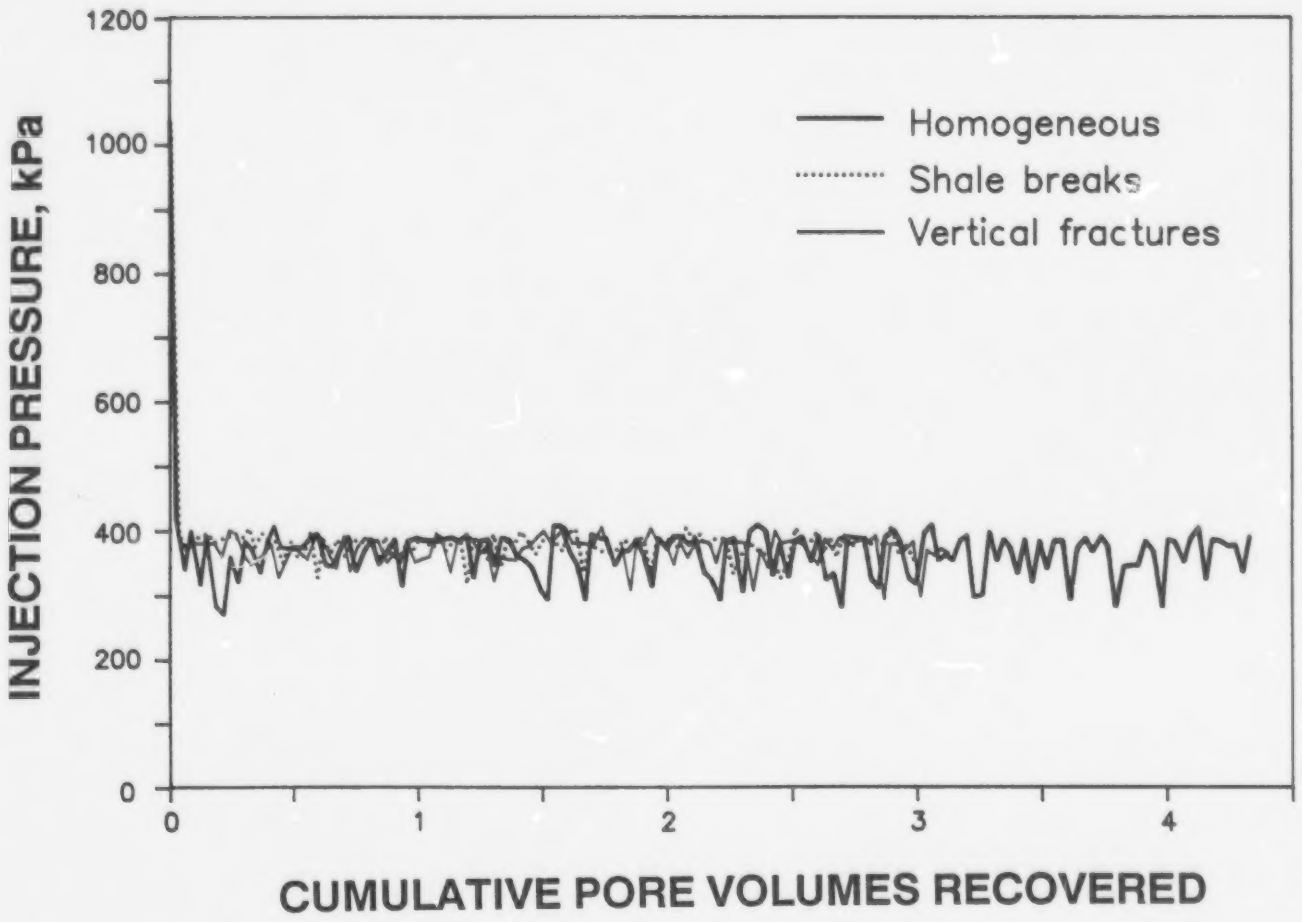

Figure 42. Effect of Reservoir Heterogeneity on Injection Pressure for Bottom-Water Reservoirs ($h_o/h_b=5$)

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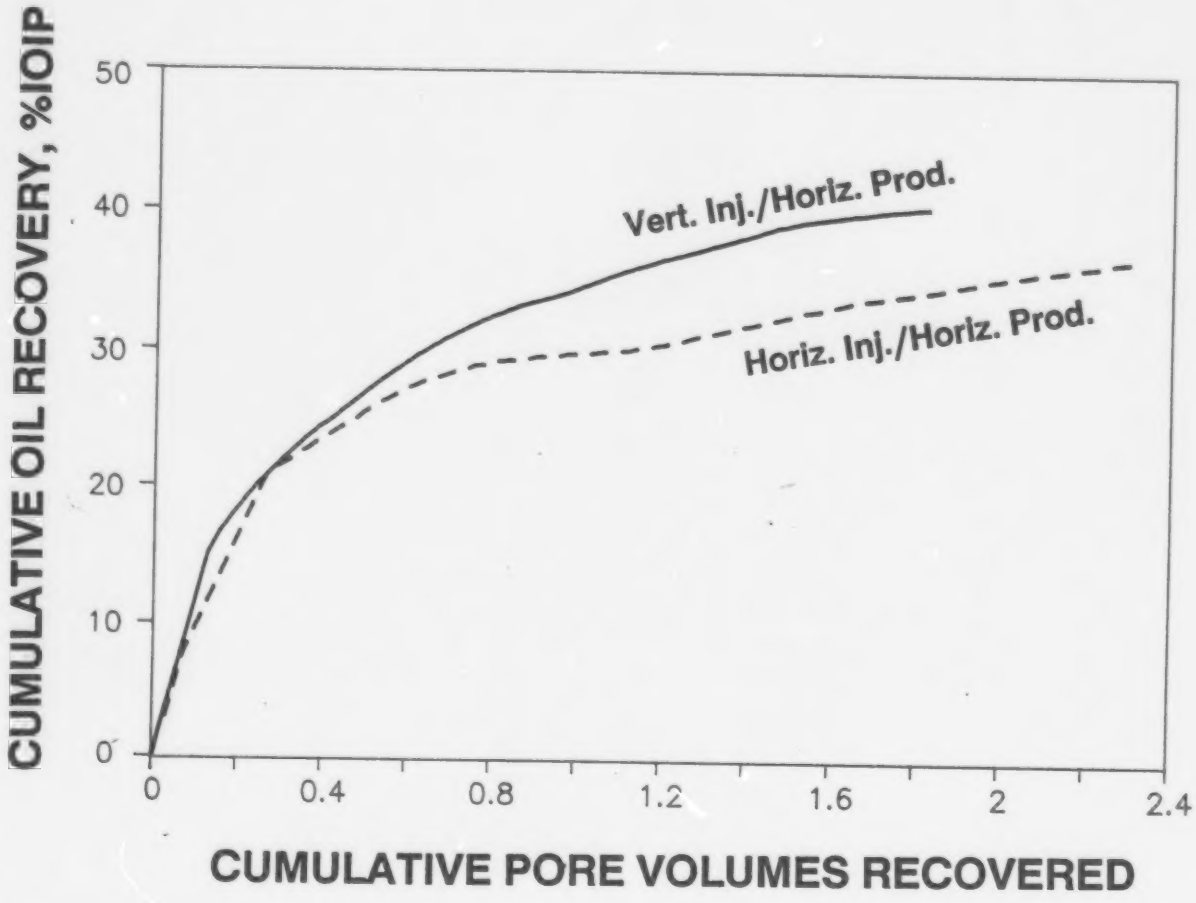

Figure 43. Effect of Injection/Production Strategy on Oil Recovery

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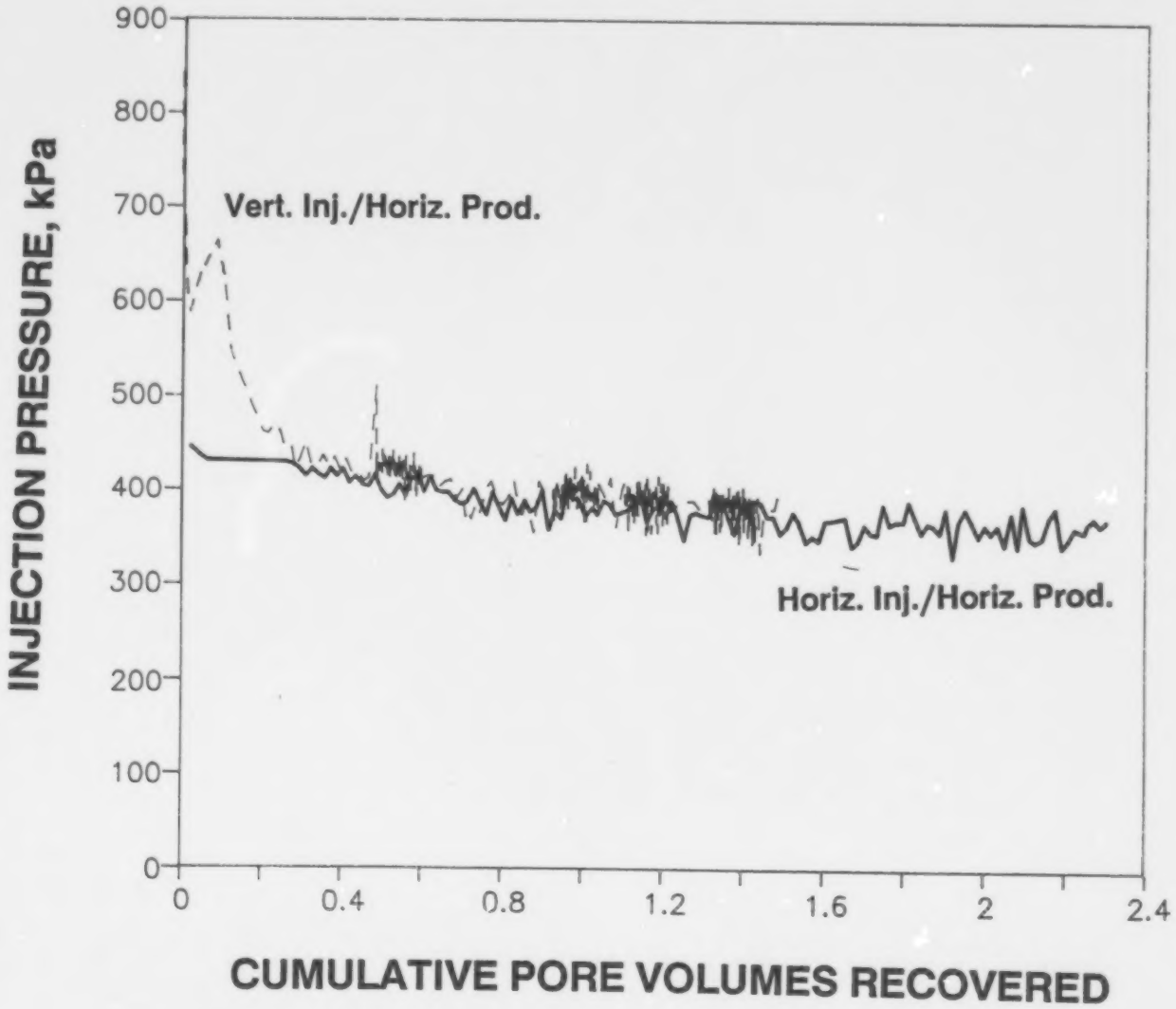

Figure 44. Effect of Injection/Production Strategy on Injection Pressures

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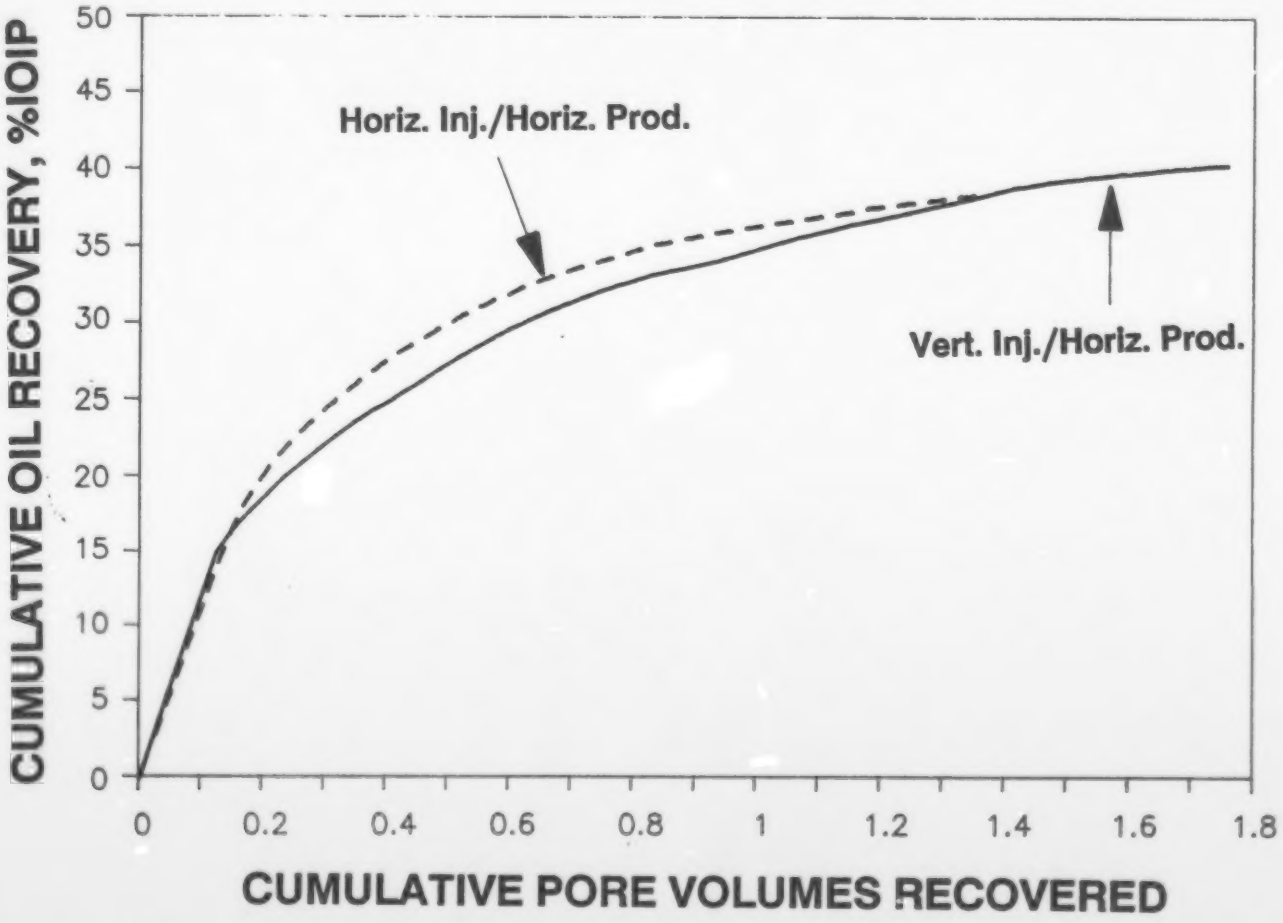

Figure 45. Comparison of Oil Recoveries for Large Diameter Horizontal Well with Vertical Injector/Horizontal Producer Case

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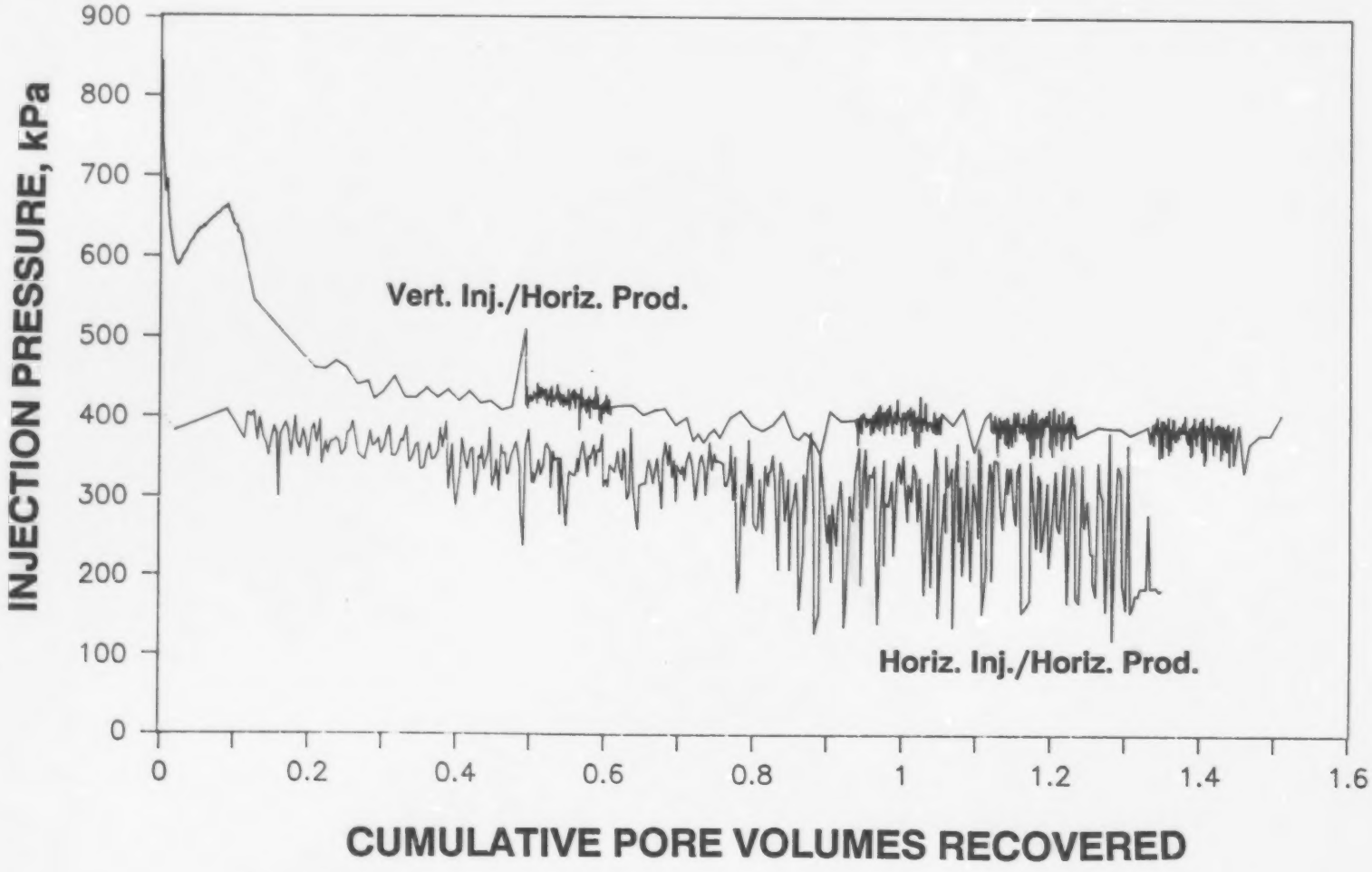

Figure 46. Comparison of Injection Pressures for Large Diameter Horizontal Well with Vertical Injector/Horizontal Producer Case

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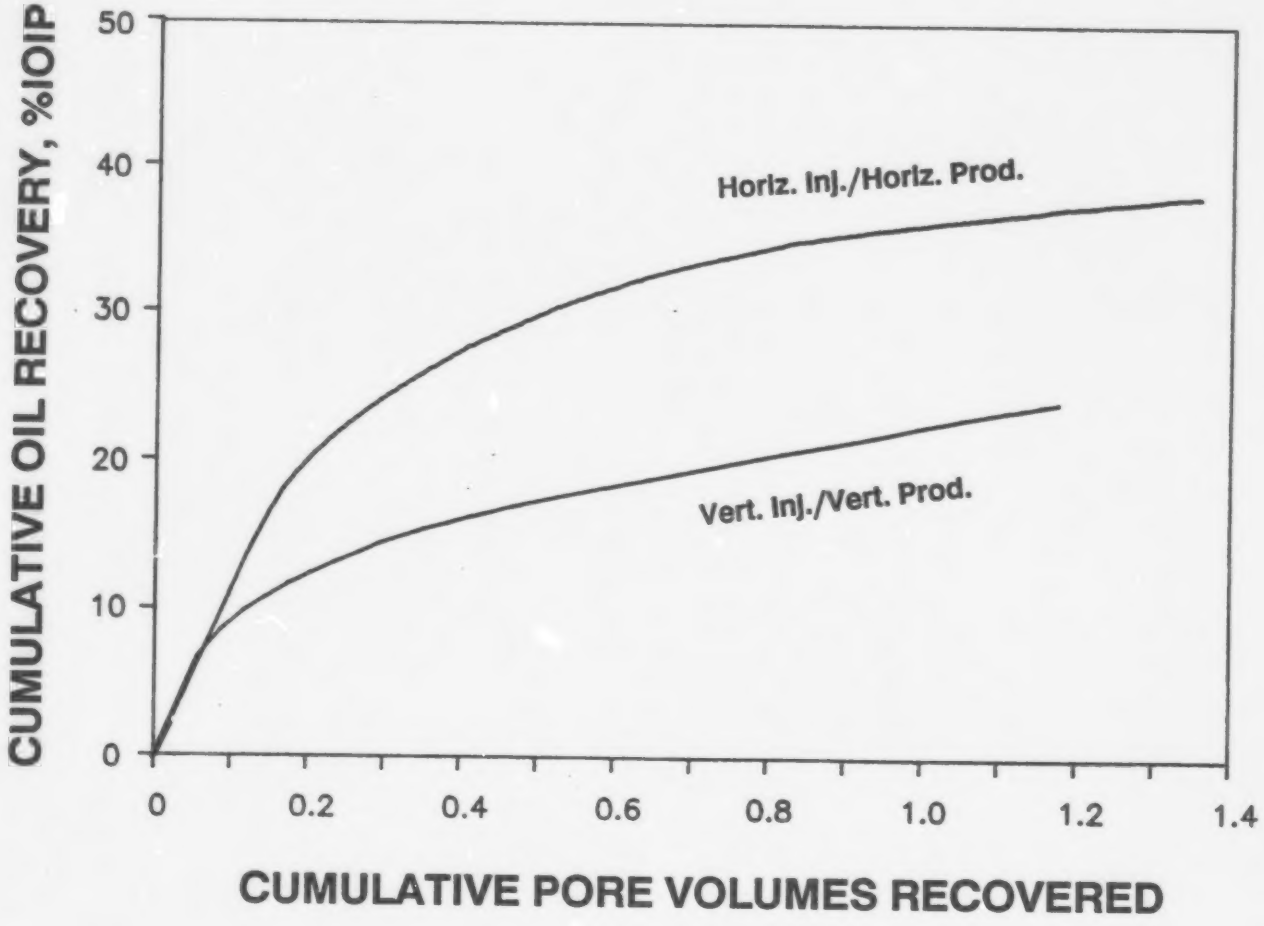

Figure 47. Comparison of Oil Recoveries for Runs 1 and 15

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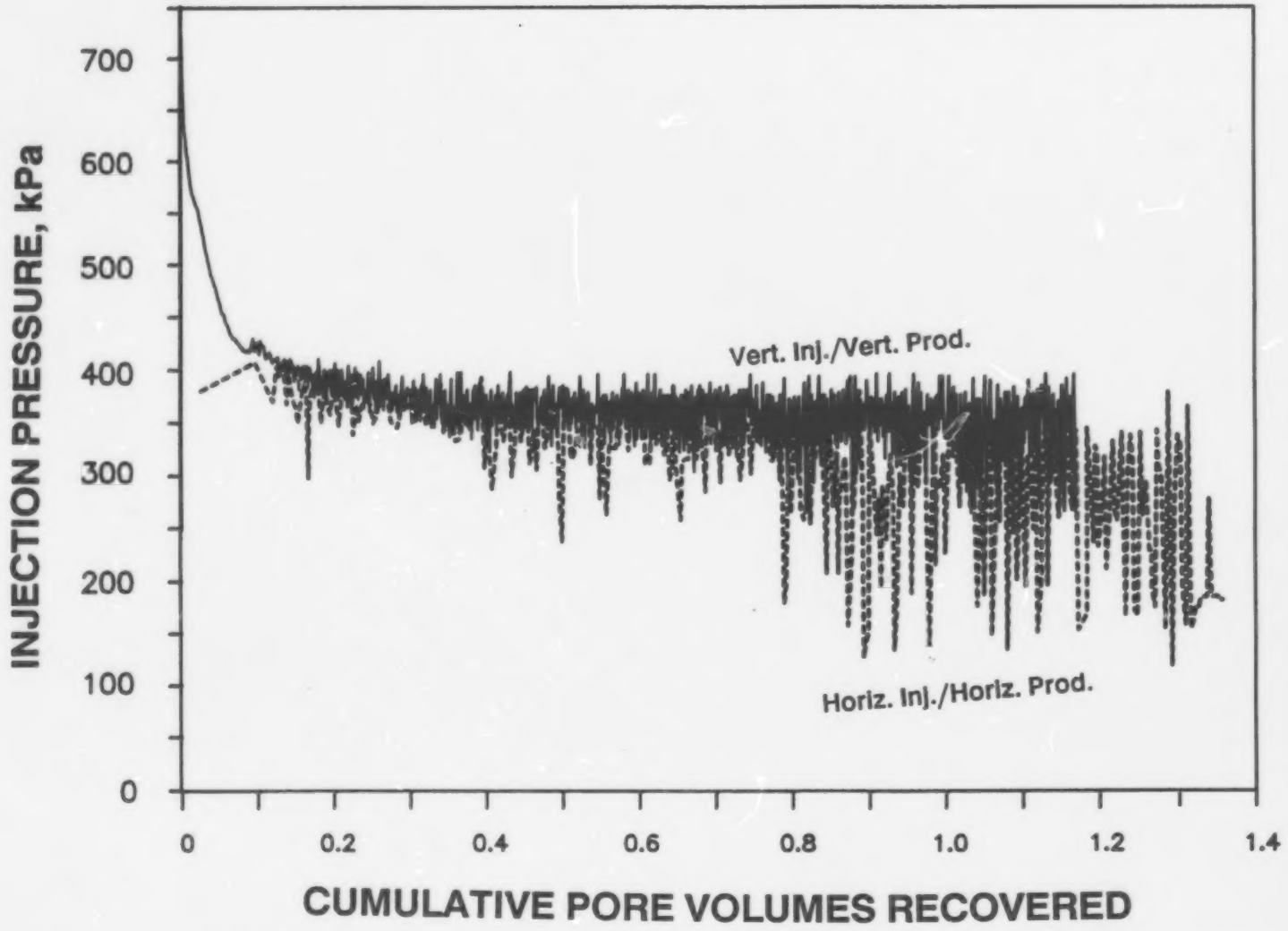

Figure 48. Comparison of Injection Pressures for Runs 1 and 15

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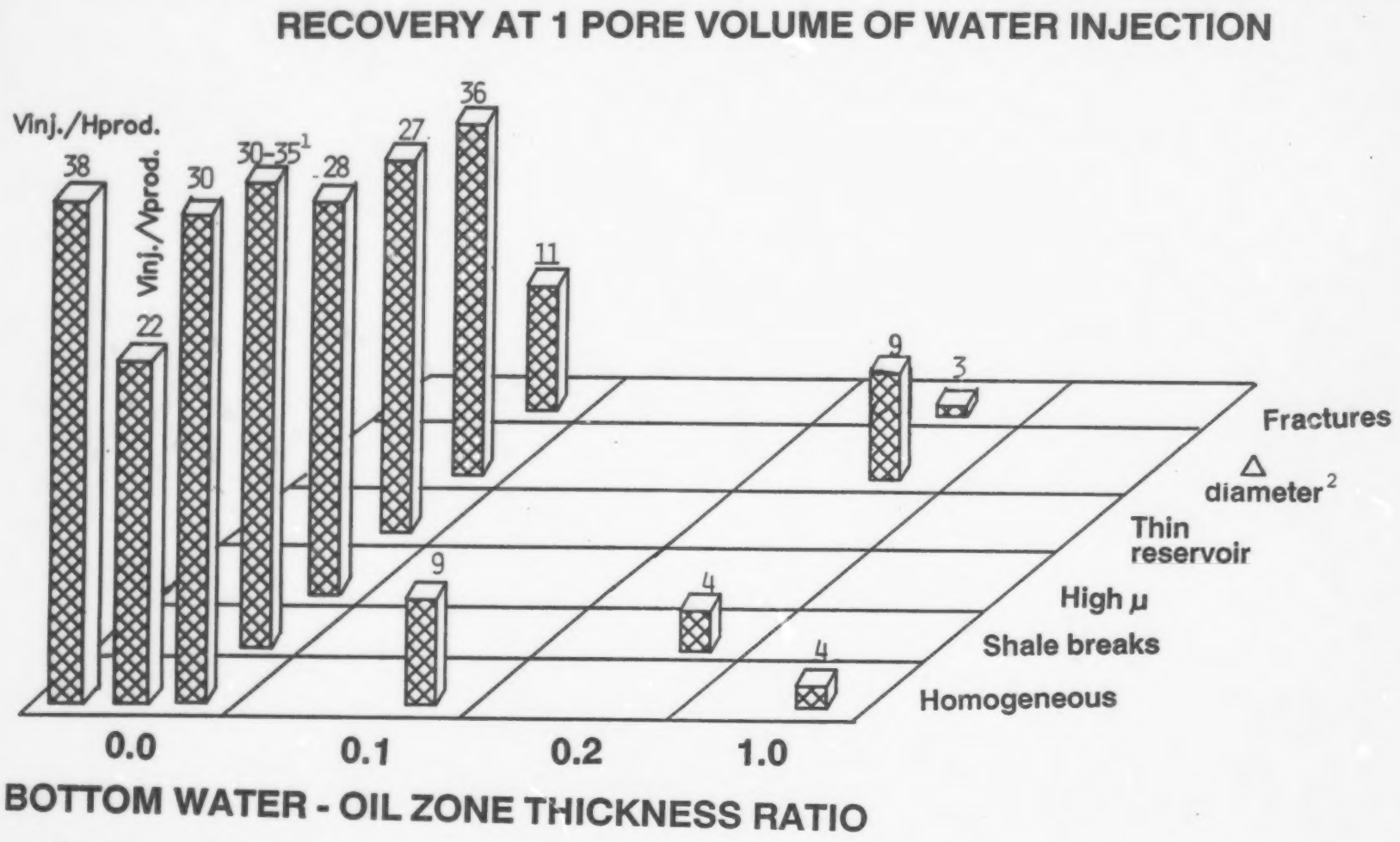
FIGURE 49. Comparison of Oil Recoveries at 1 Pore Volume of Water Injection for Various Cases



1. Thin reservoir
2. The case without bottom water used a large diameter production well rather than the small diameter scaled production wells used elsewhere. This bottom water case used a large diameter injector (as did all non-bottom water runs shown)while all other bottom water cases used a small diameter scaled injector.

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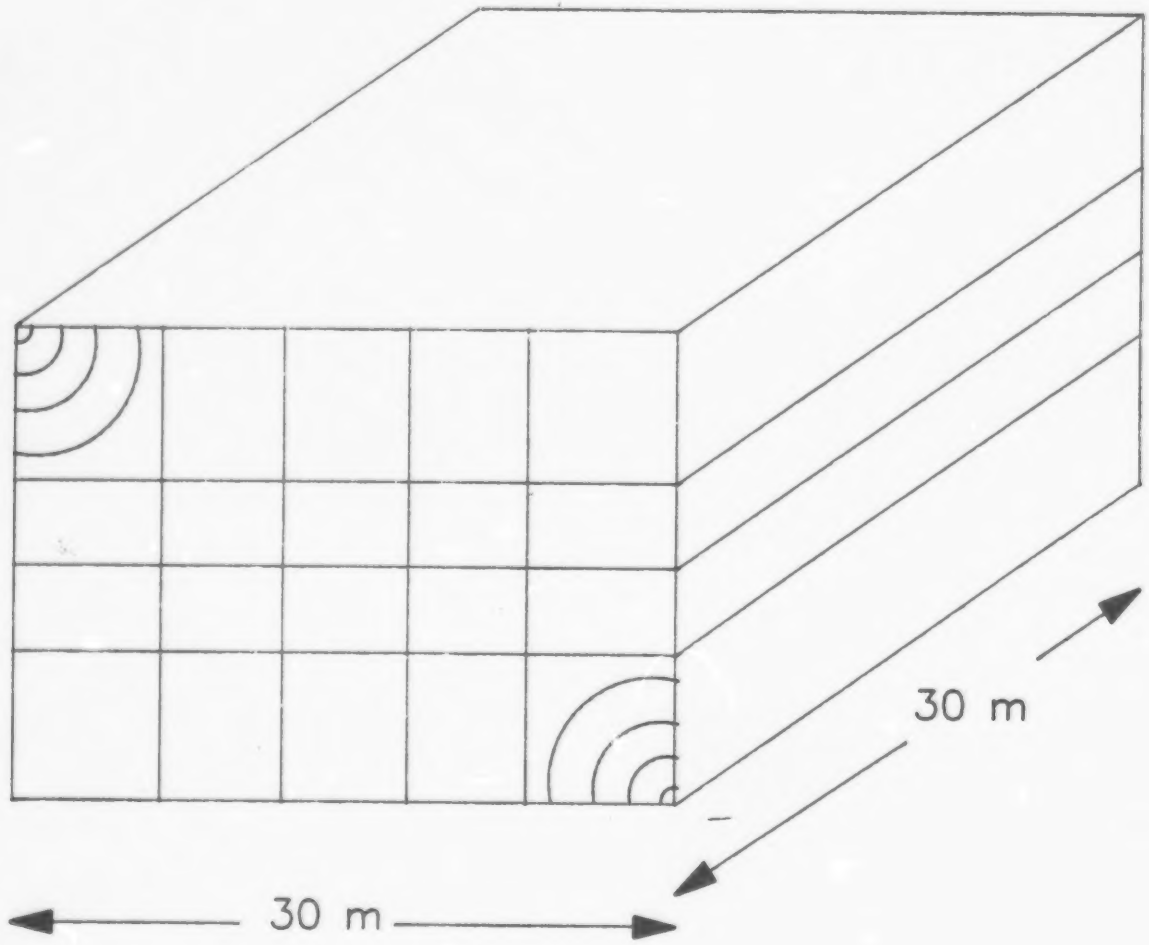

Figure 50. Grid Distribution for Numerical Simulation

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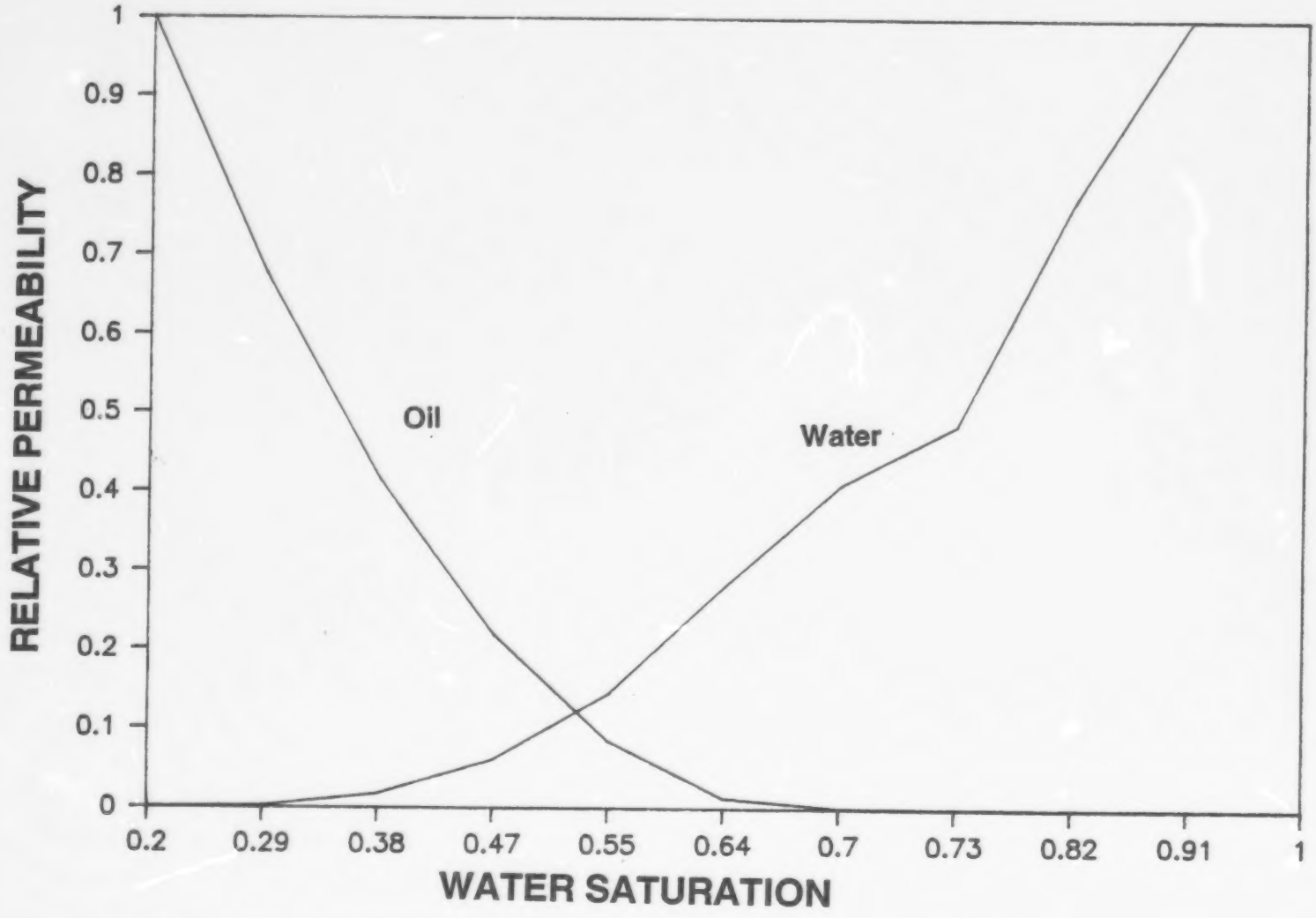

Figure 51. Relative Permeability Curves Used for Numerical Simulation

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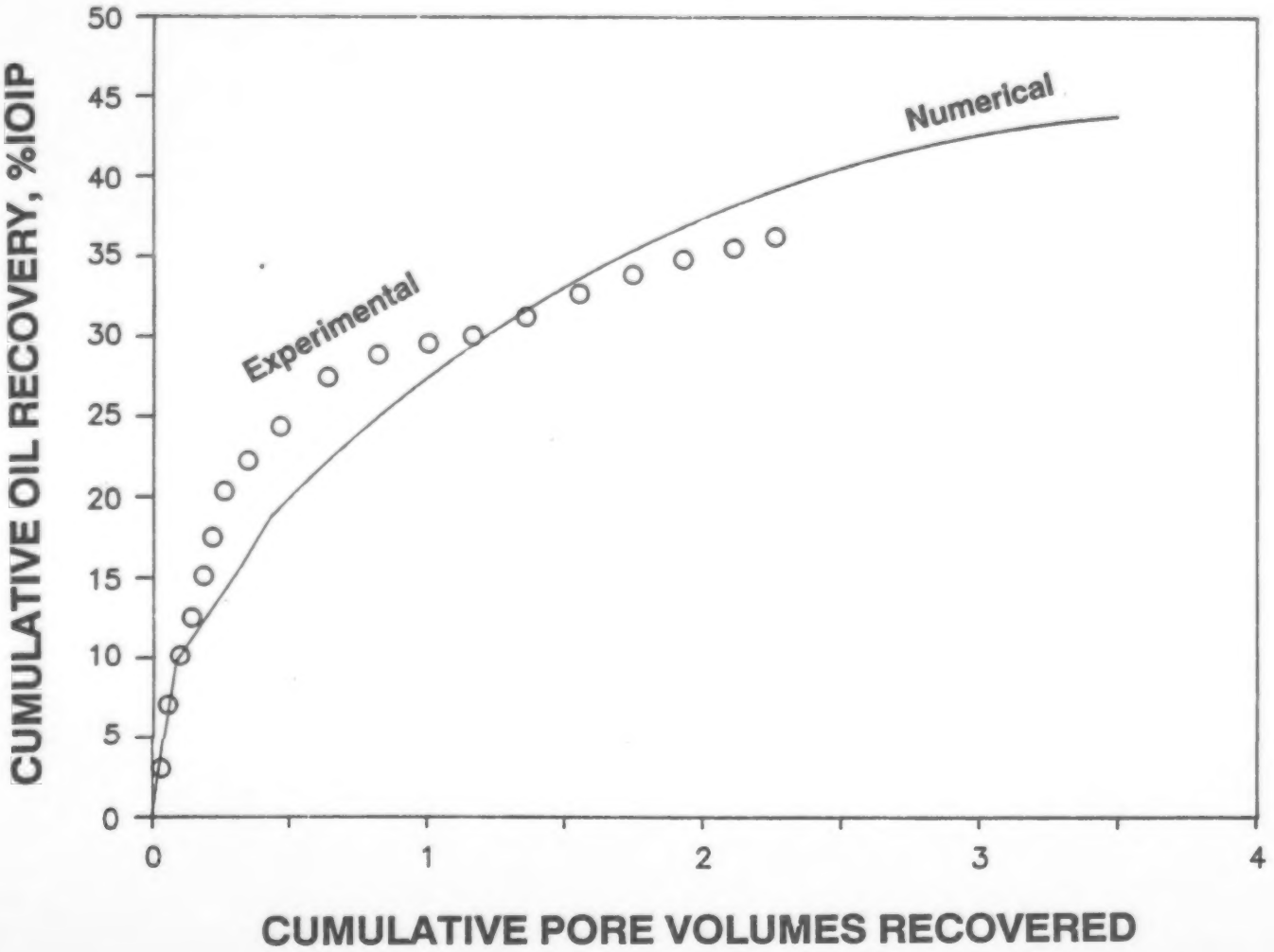

Figure 52. Comparison of Experimental and Numerical Simulation Results of Run 1

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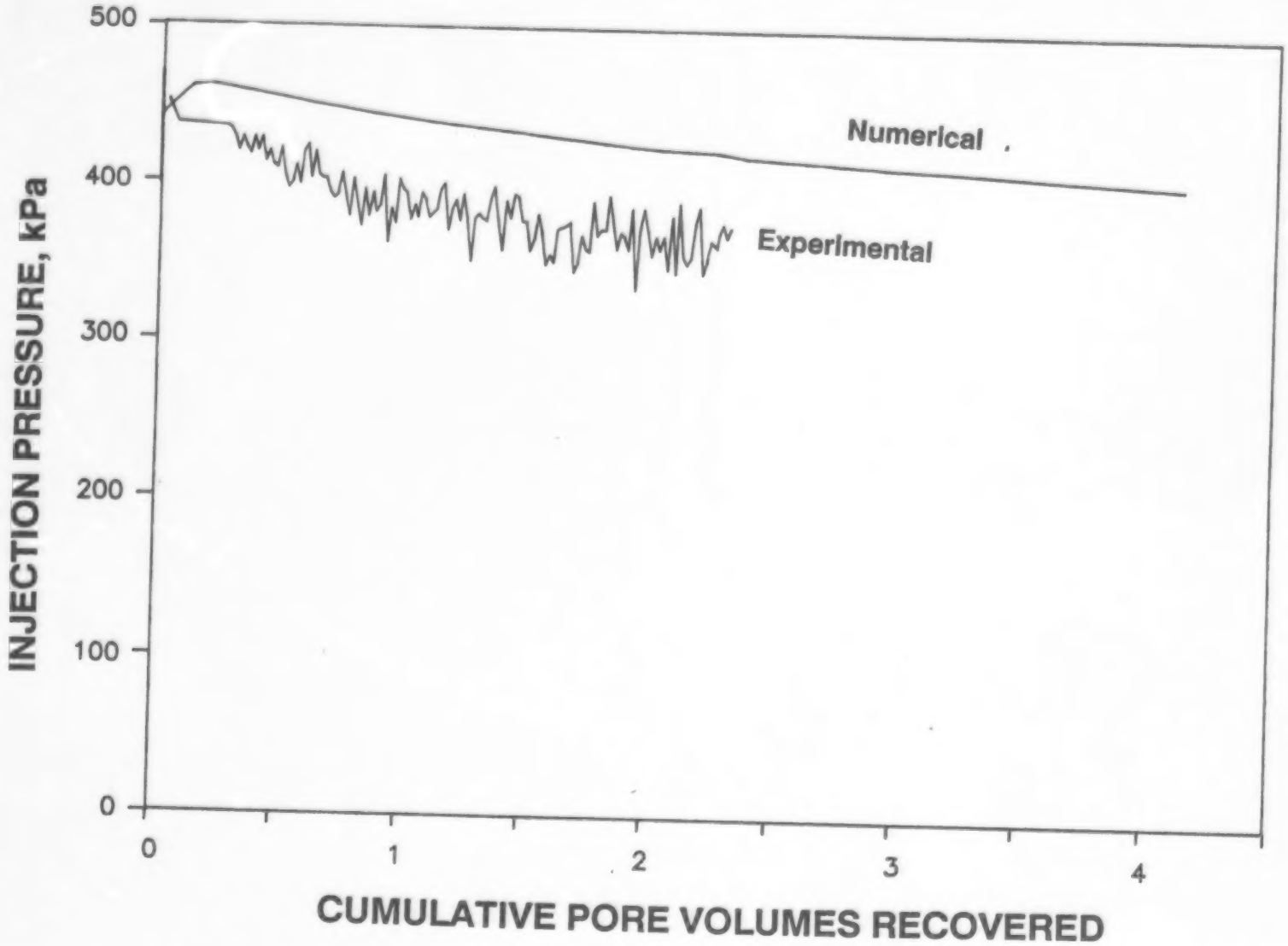

Figure 53. Comparison of Experimental and Numerical Pressures of Run 1

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APPENDIX "C"

DISCLOSURE CERTIFICATION

To be completed by the Contractor and returned to:

Dr. R.G. Agarwal
Senior Science Procurement Officer
Science Branch
Science and Professional
Services Directorate
Department of Supply and Services
11C1, Place du Portage, Phase III,
11 Laurier Street
Hull, Quebec
K1A 0S5

CONTRACT TITLE: SCALED MODEL STUDIES OF HEAVY OIL RECOVERY USING HORIZONTAL WELLS IN HEAVY OIL RESERVOIRS [Part of Energy, Mines & Resources Cost-Shared Energy Conversion Program and Part of the Program of the Federal Panel on Energy R&D (PERD)]

CONTRACT FILE NUMBER: 06SQ.23440-8-9232

CONTRACT SERIAL NUMBER: 23440-8-9232/01-SQ

☐ We certify that all applicable disclosures were submitted in compliance with General Conditions Research and Development and in accordance with the contract and the Science Procurement Officer's instructions.

OR

☐ We certify that there are no disclosures to submit under the above referenced contract, referred to in General Conditions Research and Development.

SIGNATURE: [signature]

PRINT NAME: GEORGE DYSON

TITLE: DIRECTOR, TECHNICAL SERVICES

COMPANY NAME: NOVA HUSKY RESEARCH CORPORATION

DATE: 90/04/09